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Canadian Natural Gas

Review of 2007/08 & Outlook to 2020

December 2008

Natural Gas Division

Petroleum Resources Branch

Energy Sector

Canada

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Foreword

Canadian Natural Gas: Review of 2007/08 & Outlook to 2020 is an annual working paper prepared by the Natural Gas Division of Natural Resources Canada. It provides summaries of natural gas industry trends in Canada and the United States (US).

The objective of this report is to provide an understanding of the current state of the North American natural gas market in a format that can be quickly and easily read.

■ Structure of the Report

The report is divided into three major sections. Section 1 contains the conclusions and Executive Summary. Section 2 reviews the calendar year 2007 and, where data is available, year-to-date 2008, to provide a historical record of the year, and a perspective on recent natural gas market dynamics. It is a structured look at natural gas market fundamentals – supply, demand, etc. Section 3 provides a long-term (to 2020) analysis of Canadian and US natural gas fundamentals.

■ Sources

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the US. Our main sources of statistical data were the National Energy Board (NEB), the US Energy Information Administration (EIA), and Statistics Canada.

While every effort is made to provide the most recent data, many sources are continually revising their data. As a result, data for recent years may differ slightly from what was reported in last year's report.

■ Natural Gas Division Background

The Natural Gas Division is part of the Petroleum Resources Branch, which also includes the Oil Division, the Frontier Lands Management Division, the Energy Infrastructure Protection Division, the International Division, and the Strategic Policy Division.

The Natural Gas Division provides expert technical, regulatory, policy and economic information and advice on natural gas issues to the Minister of Natural Resources Canada and the federal government.

In addition, the Natural Gas Division advises the Minister of Natural Resources Canada on matters related to statutory obligations under the *National Energy Board Act* and the *Transportation Safety Board Act*. The Natural Gas Division also manages the Pipeline Arbitration Secretariat.

■ Natural Gas Division Website

This report is available online at our website: http://www.ngas.nrcan.gc.ca. Other Natural Gas Division reports, including previous versions of this report, are also available at this website. The Internet version appears in full colour format and can be printed as such with a colour printer.

■ We Value Your Feedback

We appreciate your comments, suggestions, and questions. Questions and comments can be directed to John Foran at:
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Canadian Natural Gas:
Review of 2007/08 & Outlook to 2020

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Executive Summary

■ 2007 Market Summary

In 2007, North American natural gas demand reversed a three-year trend of decline. Demand increased by 7% compared to 2006, and reached 71.7 billion cubic feet per day (Bcf/d).

The increase, which was partly driven by colder winter weather, resulted in an additional 1.7 Bcf/d of demand for space heating in the residential and commercial sectors. The power generation sector added nearly 1.8 Bcf/d of incremental demand. US natural gas demand to generate power has increased 32% since 2000.

In Canada, driven by higher residential and commercial demand and also by a sector that has shown constant demand growth—the Alberta oil sands—demand was up 10% (up 0.8 Bcf/d). Natural gas is used in the recovery and upgrading of oil sands. In 2007, natural gas consumed by oil sands producers was 412 Bcf, up 17% from 2006. This represents 13% of total Canadian gas demand.

The two main North American natural gas markets—Henry Hub and the Intra-Alberta market—saw monthly prices average US$6.86 per million British thermal units (MMBtu) and C$6.27 per gigajoule (GJ) respectively in 2007. This compares to average annual Henry Hub and Alberta prices of US$7.23/MMBtu and C$6.79/GJ in 2006.

■ 2008: The End of the Supply-Limited Natural Gas Market?

While data for 2008 is still preliminary and incomplete, this preliminary data indicates that major changes are occurring in North American natural gas markets.

In our report last year, we used the term "the supply-limited natural gas market" to describe North America over the 2001 to 2006 period.

North American domestic supply growth had essentially stopped by 2001 because of basin maturity. By 2001, most North American supply areas had been well-explored, and finding new natural gas to replace production became more difficult; pool sizes and initial production rates fell; the number of new natural gas wells needed to replace the older exhausted wells skyrocketed; and finding and production costs increased.

Markets rebalanced demand with the suddenly limited supply by driving prices much higher so that some customers shed gas load. This occurred most significantly in the industrial sector where higher prices shut in operations.

Due to flat supply, North American natural gas demand over this period was stagnant.

As a result of high natural gas prices, suppliers looked to new areas and employed new production and drilling techniques to make gas flow from areas or reservoir types once deemed uneconomic or 'unproduceable' i.e. coalbed methane, tight gas and shale gas.

The success of these new sources in the US is now evident and significant. According to US EIA data, US Lower-48 production from January to September 2008 is up 8.4% (4.3 Bcf/d) over the same period in 2007. US production in 2007 was up 3.6% (1.8 Bcf/d) over 2006.

While Canadian natural gas production for the moment continues to decline slowly, unconventional gas development is expected to eventually result in higher Canadian production.

Commercial shale production is expected in Canada by 2009. Producers are paying record prices for shale prospective land in northeast BC, and activity is occurring in Quebec, Nova Scotia and the McCully field in New Brunswick.

For 2008, prices at AECO and Henry Hub have averaged 23% and 32% higher than prices in 2007 respectively, largely the result of high

prices early in the year. Prices have since fallen dramatically—with natural gas prices in December 2008 similar to average monthly prices in 2007.

While there are several factors driving natural gas price levels, the two most important factors in recent months have been the dramatic increase in US Lower-48 natural gas production—driving prices lower—and the volatility in the price of crude oil—driving prices both up and down. The West Texas Intermediate (WTI) price of crude oil peaked at US$145/barrel (bbl) in July 2008 and fluctuated between US$45-60/bbl during the fourth quarter of 2008.

Deliveries to the US of liquefied natural gas (LNG) have experienced a roller coaster ride over the last 20 months. After increasing 32% (189 Bcf) in 2007, deliveries fell considerably in 2008.

US LNG deliveries fell despite the addition of one offshore LNG terminal in 2007 and two new large LNG import terminals in the US Gulf Coast in 2008. While these terminals added significant new import capacity, physical deliveries to the US have declined considerably from an average of 2.1 Bcf/d in 2007 to 1.0 Bcf/d in 2008. US natural gas production growth in 2008 has resulted in less demand for LNG in North America.

Thus, while in early 2008 North American natural gas markets appeared to be destined to rely increasingly on LNG, it now appears that higher production from domestic unconventional basins could shut out some LNG volumes.

On the supply side, total 2007 North American domestic natural gas production increased 501 Bcf (2%), to reach 25.0 trillion cubic feet (Tcf). The year 2007 marked the second consecutive year of production increases and also reversed the trend of three consecutive years of production declines from 2003 to 2005.

The entire increase in 2007 North American natural gas production came from US supply basins. US production was up 4% (660 Bcf) and Canadian production declined 3% (159 Bcf) for an overall increase of 2% in North American production. The largest gains in the US came from the Gulf of Mexico onshore region where production increased 462 Bcf, largely due to increased shale production from the Barnett shale in Texas. Gulf of Mexico onshore drilling in 2007 was up 11% compared to 2006.

Another US region experiencing growth in production is the US Rockies, mainly Wyoming. In 2007, Wyoming increased production by 93 Bcf, or 6%, despite a 7% decline in drilling. The mainstay of Rockies production is from unconventional sources such as coalbed methane (CBM) and tight gas.

Canadian and US drilling continued to diverge in 2007, with the US recording a 4% increase and Canada recording a dramatic 25% decline. A large portion of the Canadian decline was experienced in Alberta. Causes cited for the decline are a mature basin and higher royalties to be paid by producers starting in 2009.

In the US, drilling is increasingly targeting successful unconventional gas plays, including shale gas in Texas, Arkansas, and Oklahoma, and CBM and tight gas in the US Rockies.

In the area of natural gas reserves, 2007 will go down as a historic year in the US. US net reserve additions were the largest on record at 26.6 Tcf (46.1 Tcf of reserves added minus 19.5 Tcf of production)—double any other year on record. Total US reserves at year-end 2007 stood at 238 Tcf, 47% higher than the low of 152 Tcf in 1993.

The largest additions occurred in Texas and the Rockies, where unconventional natural gas exploration, development and production are advancing rapidly.

In the 2007 calendar year, North American storage volumes fell from 3.5 Tcf on January 1, 2007, to 3.3 Tcf on January 1, 2008, a decline of 160 Bcf. This represents a decline of 5% for the year. A negative storage change means more gas was pulled from storage through the year than was injected—primarily a

result of colder 2006-07 winter temperatures. Heading into the 2008-09 winter, as of November 1, 2008, total North American storage levels were at near capacity (4.0 Tcf), and only slightly below the record storage levels set in 2007. These high levels are contributing to fairly stable prices.

In 2007, export prices were lower, but volumes and revenues were higher compared to 2006. Gross export volumes reached record levels in 2007 at 3,785 Bcf—an increase of 260 Bcf, or 7% from 2006 volumes. These higher volumes, despite lower international border export prices—down 5% at C$6.82/GJ—led to an increase in export revenues—up 2% to C$27.9 billion.

Net exports in 2007 represented about 56% of total gas produced in Canada. Since 2001, net exports have typically accounted for 55% to 60% of total Canadian production.

Imports into Canada were at a record 466 Bcf in 2007, a 36% increase over 2006 levels. The rise in imports moderated the rise in net exports, resulting in a 4% increase for 2007.

■ Natural Gas Market Outlook to 2020

Note: For each variable reported, three to five forecasts from a variety of respected sources such as consultants and government agencies were averaged to obtain a "consensus view" of the outlook for that variable to 2020. The consensus forecast for each variable is calculated using an average of the individual forecasts available for that variable. The individual forecasts used were the most recent at the time of the publishing of this report.

This method indicates a growth rate of 1.5% per annum as the consensus forecast for North American natural gas **demand** in 2020 shows demand growing from 25.9 Tcf in 2008 to 30.8 Tcf in 2020. This year's consensus forecast for demand in 2020 is 1.2 Tcf higher than last year's consensus forecast.

US demand growth is driven mainly by growth in the power generation sector, where natural gas consumption is forecast to rise from 6.8 Tcf in 2008 to 9.1 Tcf in 2020, and account for about 66% of total demand growth in the US and 50% of total North American demand growth. Industrial demand is expected to rise by 0.4 Tcf.

In Canada, industrial and power generation demand account for 70% and 21%, respectively, of the expected growth in Canadian demand over the forecast period. Industrial demand is driven mainly by oil sands in Alberta and power generation demand will mostly be situated in Alberta and Ontario.

Overall, North American natural gas **supply** is expected to increase from 25.8 Tcf in 2008 to 30.8 Tcf in 2020. Forecasts anticipate North America will experience higher production from domestic unconventional supply basins in both the US and Canada.

The outlooks for Arctic gas and LNG imports are considerably more pessimistic than last year's forecast. LNG imports to the United States in 2020 are now forecast at 6.2 Bcf/d—down 55% from our previous report's forecast of 13.9 Bcf/d by 2020. Despite the downward revision, the consensus forecast suggests LNG will supply 11% of North America's energy needs in 2020.

While the long-term impacts of LNG supply to North America are difficult to predict, one clear conclusion is North American natural gas prices with LNG will be lower than without LNG. LNG supply will moderate prices to some degree, and allow for higher levels of natural gas supply and demand.

As LNG deliveries to North America rise, the influence of LNG on North American natural gas prices will strengthen. However, North American natural gas markets are not expected to integrate with European or other markets (i.e., prices tracking each other) in the foreseeable future because LNG is not expected to set prices in North America.

Natural gas will continue to be substitutable with petroleum products (or even coal) in the

electricity generation sector, so the prices of North American natural gas and world crude oil will continue to influence one another. The prices of both will continue to be largely unpredictable, as indicated by the dramatic fall in crude oil prices in 2008 from a high of nearly US$150/bbl in July to $50/bbl in November.

With respect to natural gas prices, the consensus in this year's report points to higher prices than in the previous report. The consensus forecast in our previous report saw US Henry Hub prices at US$8.71/MMBtu in 2020 versus the consensus this year of US$10.42/MMBtu in 2020. Similarly, the forecast for prices in Alberta this year is C$10.35/GJ compared to last year's forecast of C$8.28/GJ.

The consensus forecast for Canadian production is 5.9 Tcf in 2020, the same as the volume produced in 2007. However, production is expected to decline in the next few years, bottoming out at 5.4 Tcf in 2013 before rebounding to 5.9 Tcf in 2020.

Due to a relatively flat supply in western Canada and rising Canadian demand, net Canadian exports of natural gas to the US are expected to fall. This will partly be driven by rising imports of natural gas to Canada—mainly through Ontario—from the US. As a result of these trends, net exports from Canada to the US are projected to fall from 3.2 Tcf in 2007, to 2.3 Tcf in 2020.

Compared to last year, the consensus for Canadian natural gas production is slightly more bearish in the short-term as lower drilling impacts short-term production growth. However, by 2013, new production from BC shale will begin to reverse the declining trend, and by 2018, the Mackenzie Gas Project will add an additional 0.7 Bcf/d to Canadian production.

■ Policy Implications

Energy supply is necessary for the North American economy and way of life. One of the major elements of the US and Canadian natural gas policy over the past 20 years has been unregulated natural gas commodity prices. Unregulated prices have allowed the provision of natural gas to consumers and industry at the lowest possible cost. Producers will not provide natural gas at prices below cost. The North American model—unregulated prices and hundreds of suppliers—relies on competition to keep prices very closely related to costs.

At the same time, considering its benefit to the consumer and the prices of alternative energy sources, unregulated prices allow natural gas to be priced at its true value. These prices encourage producers to develop new supplies as existing pools are depleted. New projects and areas such as the Mackenzie Gas Project, the Alaska gas pipeline, LNG import terminal projects, and unconventional natural gas supplies are being pursued under this model.

As the combination of new unconventional supplies, northern gas development, and LNG imports have the potential to solve the problem of limited natural gas supply, one objective of policymakers is to facilitate the development of these new sources.

At the same time, any industrial development which has the potential to impact the environment or public health and safety must be regulated to ensure such impacts are prevented or mitigated.

To accomplish both goals, regulation and policies must be effective and efficient and should not impede new economically feasible, environmentally sustainable, socially responsible and safe natural gas supply developments.

Effective regulation and policy development takes time, resources, and a comprehensive understanding of natural gas and LNG markets. The research and publication of this report is one tool used to build understanding of natural gas and LNG markets. The creation of this report also promotes market transparency, which can aid in market efficiency, and public education—an important factor for policy development and the regulatory process.

Review of 2007/08

■ North American Natural Gas Demand

This review section reports on final and complete 2007 data. As data from 2008 is partial and incomplete, only numbers that are available are reported.

The table at right shows 2007 versus 2006 natural gas demand in Canada and the US. In 2007, North American natural gas demand grew by 1,685 billion cubic feet (Bcf), or 7%, rising to nearly 26.2 trillion cubic feet (Tcf). By far the largest portion of this growth (39%) occurred in the US electric power generation sector which grew 10% to nearly 6.9 Tcf.

Natural gas consumed by the weather-sensitive residential and commercial sectors in Canada and the US increased a combined 624 Bcf year-on-year, accounting for 37% of market growth. This was driven by colder winter weather in major consuming regions.

In Canada, the industrial/power generation sector added 185 Bcf of demand—an increase of 13%—driven largely by greater natural gas consumption by oil sands operators. Small gains were also recorded in the US industrial sector (up 139 Bcf).

US LNG exports and pipeline exports are covered in this demand section, as they are a "disposition" of US gas supply. Both US pipeline exports to Mexico and LNG exports to Japan via Alaska declined in 2007.

North American Natural Gas Demand				
	2007	2006	Change	
	Bcf	Bcf	Bcf	%
US Residential	4,724	4,368	356	8%
US Commerical	3,005	2,835	170	6%
US Industrial	6,633	6,495	139	2%
US Electric	6,874	6,222	652	10%
US Other[1]	1,817	1,732	85	5%
Total US Demand	**23,053**	**21,652**	**1,401**	**6%**
US Gross LNG Exports	47	61	-14	-24%
US Gross Exports to Mexico	288	322	-34	-11%
Total US Disposition	**23,388**	**22,035**	**1,353**	**6%**
Canada Residential	647	574	73	13%
Canada Commercial	449	423	26	6%
Canada Industrial and Power	1,618	1,433	185	13%
Canada Other[2]	400	400	0	0%
Total Cdn Gas Sales	**3,114**	**2,830**	**284**	**10%**
Total N.A. Demand	**26,167**	**24,482**	**1,685**	**7%**
Total N.A. Dispostion	**26,502**	**24,865**	**1,637**	**7%**

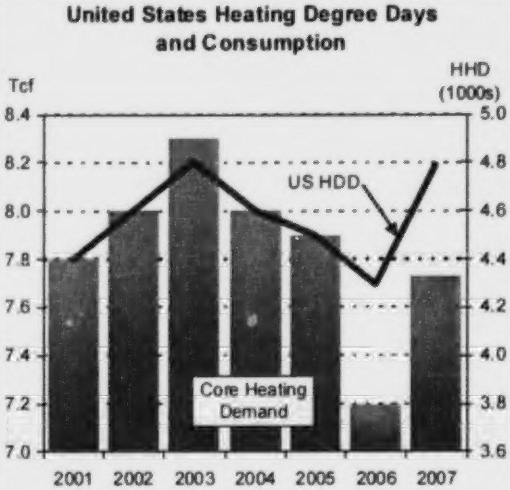
Sources: EIA, Statistics Canada and NRCan estimates
Notes: [1] US Other includes pipeline and distribution use, lease and plant fuel, and vehicle fuel. [2] Canada Other consists mainly of pipeline compressor fuel. This demand is no longer reported by Statistics Canada, and is estimated here at 400 Bcf/year.

Canadian Economic Indicators			
	2006	2007	2008 YTD
Indicator			
Gross Domestic Product[1]	1,283	1,317	1,317
Unemployment Rate	6.3%	6.0%	6.0%
Exchange Rate (C$/US$)	1.13	1.07	1.04
Interest Rate[2]	4.3%	4.6%	3.6%
Total CPI Inflation	2.0%	2.2%	3.5%
TSX Composite Index[3]	12,908	13,833	8,988

Sources: Statistics Canada, Bank of Canada, EIA, GLJ, TSX
Notes: [1] Reported in 2002 dollars (billions). [2] Three-month Treasury Bill. [3] Annual close, 2008 data is closing value of the S&P/TSX Composite Index on December 31, 2008.

■ Economic Drivers of Natural Gas Demand

Demand for natural gas in the industrial and power generation sectors is largely derived demand. That is, demand that arises due to the demand for another good or service. In the case of natural gas, this can be petrochemical products, electrical power, or any manufactured output that uses natural gas as an input. When economic conditions are strong, demand for natural gas is strong. Demand from residential and commercial sectors generally depends more on weather.



Solid North American economic conditions in 2007 led to strong growth in US and Canadian industrial and electrical demand for natural gas.

> **Natural Gas Demand: Oil Sands Technology**
>
> The oil sands industry requires significant amounts of natural gas to extract and process bitumen. In an effort to limit consumption, oil sands facilities often use co-generation to maximize efficiency by producing both electricity as well as steam for their heating requirements.
>
> In addition, the oil sands industry is continually developing new ways to extract and upgrade bitumen more efficiently while looking for ways to reduce their reliance on natural gas. This includes: ongoing research into displacing steam with solvents in below-ground bitumen extraction; replacing natural gas with gasification technology running on solid fuels, such as the heavier components of bitumen; and exploring the potential for nuclear energy.
>
> Future technologies may lead to greater water use efficiency and enable the use of other technologies that will significantly reduce greenhouse gas (GHG) emissions.

However, the current economic environment in North America is one of great uncertainty and the general consensus among economists, governments and industry is that we are in the midst of an economic slowdown and potentially a recession, which will weaken demand for natural gas.

■ Residential and Commercial Demand

Natural gas is widely used in North America by residential and commercial sectors for space heating. Natural gas demand in these "core demand" sectors is driven mainly by cold weather in northern regions. The severity of cold weather can be measured by heating degree days (HDDs) with colder weather translating to a higher number of HDDs. For example, in 2007, US core demand increased 7% and there was a 7% increase in HDDs.

■ Industrial Demand

In recent years, relatively high North American natural gas prices have caused reductions in industrial operations that rely heavily on natural gas in their operations. Industrial demand for natural gas declined 8% between 2000 and 2007, falling from 24.4 Bcf/d to 22.6 Bcf/d. Traditional industrial uses of gas (e.g. fertilizer production, pulp and paper, iron and steel, etc.) are falling, while residential and commercial demand remains stable, and power generation demand is rising. In effect, core markets and the power generation sector continue to buy gas at the higher prices of recent years, while the industrial sector sheds gas load. Much of the lost industrial demand is not expected to return as operations have either relocated their plants overseas or shut down entirely.

In 2007, Canadian industrial/power generation demand increased 13% (185 Bcf) over 2006 due to greater oil sands demand and natural gas used to generate electricity.

The oil sands sector in Alberta continues to show constant demand growth for natural gas. According to the Alberta Energy Resources Conservation Board (ERCB), approximately 60% of the natural gas consumed by oil sands

operations is purchased from gas producers. Solution gas (gas produced by bitumen wells) and process gas (gas from upgrading operations) make up the remaining 40%. New technologies that reduce natural gas purchased by oil sands operations will also assist in reducing operations' exposure to volatile natural gas prices.

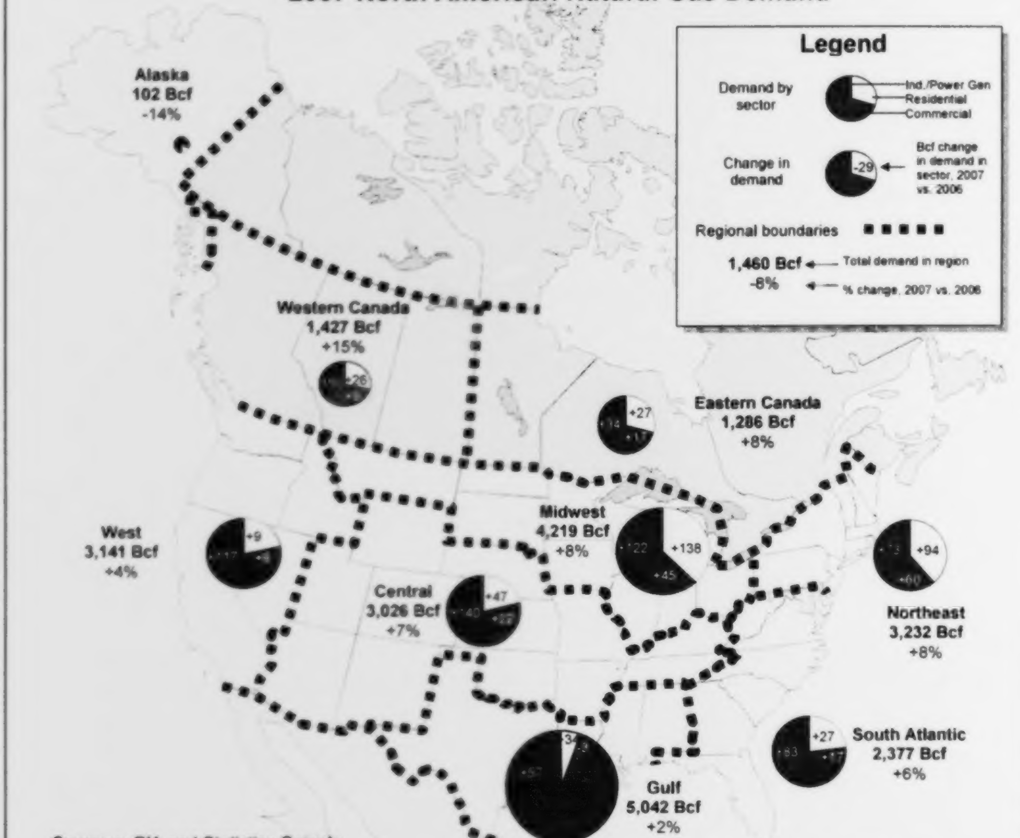
In 2007, natural gas consumed by oil sands operations for steam and electricity generation was estimated by the National Energy Board (NEB) at 412 Bcf, representing a 17% increase from 2006. This amount is equivalent to 13% of total Canadian gas demand.

While the oil sands' thirst for natural gas is expected to continue increasing, producers are applying new, innovative technologies to substitute or reduce their natural gas consumption.

■ Power Generation Demand

Natural gas for power generation has been the primary driver of North American demand growth since 2000. US demand for natural gas to generate electricity has increased 32% since 2000 and now accounts for 26% of total North American demand. In 2007, demand from US gas-fired generators increased 652 Bcf (10%) from 2006. Even with high natural gas prices,

2007 North American Natural Gas Demand



Sources: EIA and Statistics Canada
Note: US and Canada figures show end-use demand only. Pipeline, lease and plant fuel are not included. Lease and plant fuel is very significant in Alaska.

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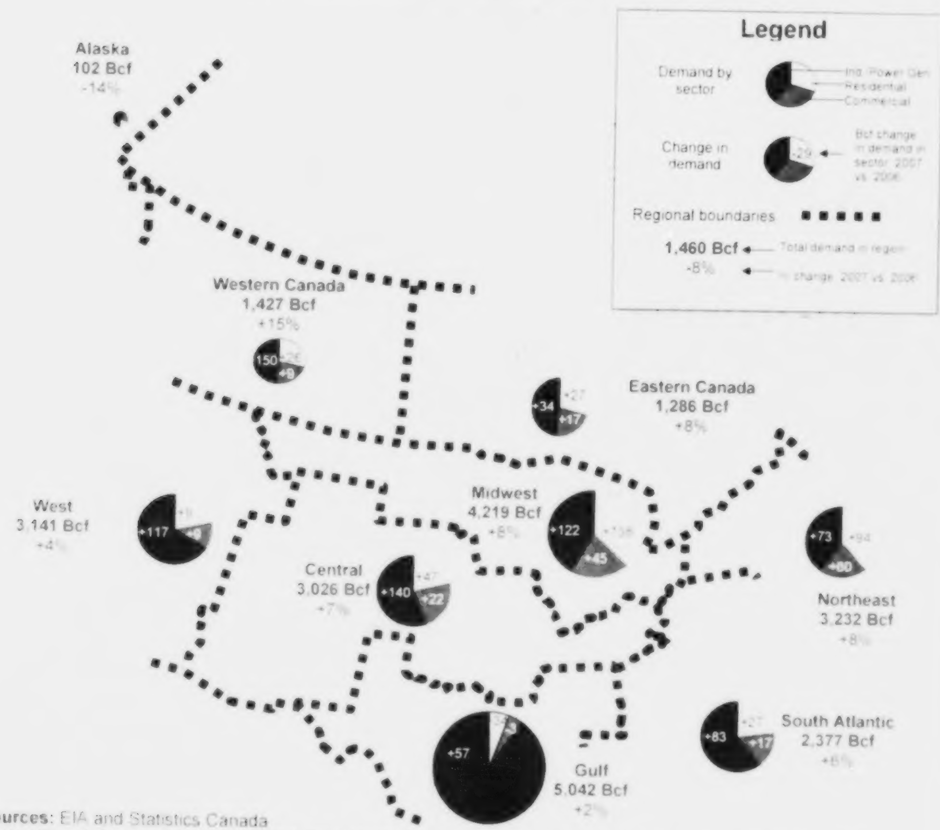

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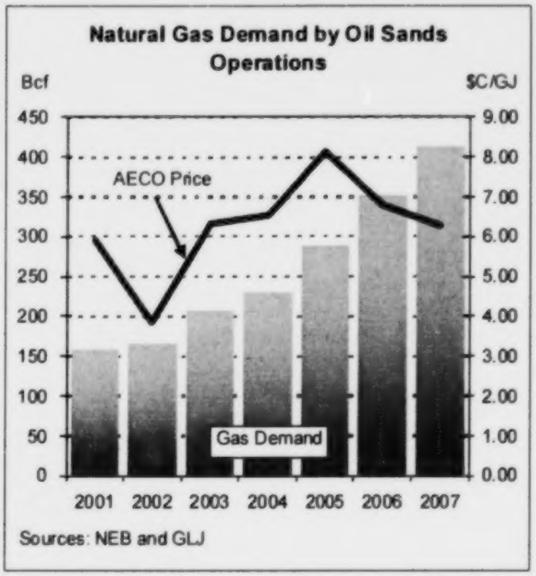
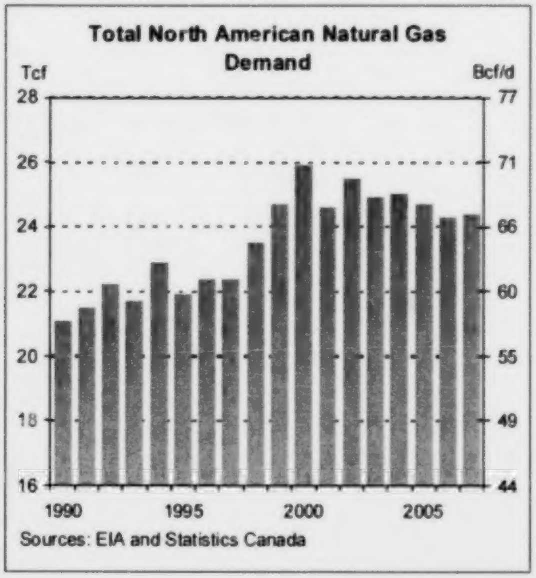


this sector has shown an increasing appetite for natural gas as environmental and cost pressures make natural gas-fired generators an attractive option for electric generation.

A contributing factor to demand growth in this sector has been warmer weather in the US, which drives increased summer air conditioning requirements, and thus, increased gas demand for electricity generation.



■ Regional Demand Trends

The map on the previous page illustrates regional natural gas demand in North America. Natural gas demand was up in every region and every sector across North America in 2007 with the exception of residential and commercial demand in the Gulf and Alaska. Western Canada demand growth led with a 15% (185 Bcf) annual increase in 2007.

Compared to 2006, in nearly all regions, colder winter weather resulted in higher natural gas use in residential and commercial sectors.

Natural gas-fired power generation demand was up in all regions of North America, most notably in the US west and Midwest. Going forward, gas-fired generation is expected to remain the main driver of North American natural gas demand growth. In addition, lower gas prices in 2007 appear to have prompted some industrial demand gains in both eastern and western Canada as well as the US central, Midwest, northeast, and west.

■ Overall North American Demand Trends

As shown in the figure at left, from 1990 to 2000, US and Canadian natural gas demand grew steadily at an average of 2% per year. Between 2000 and 2006, demand declined an average of 1% per year. The main reason for this decline was a lack of incremental gas supply at low enough prices to maintain demand.

However, in 2007, North American natural gas demand rebounded for the first time in three years (up 7%), due to lower prices, higher electrical generation demand, and a colder winter that resulted in higher core demand.

■ North American Natural Gas Supply

The following table shows total and regional natural gas supply in Canada and the US for 2007.

In 2007, North American domestic natural gas production increased 501 Bcf (2%), to reach 25.0 Tcf. This was the second consecutive year of production increases and a reversal of a trend of declining production which occurred from 2002 to 2005. However, the increase was not enough to bring production back to the peak 2001 level of 26.0 Tcf.

■ Regional Supply Increases

The North American natural gas production increase in 2007 came from the US where production was up 4%, or 660 Bcf. In Canada, production declined 3%, or 159 Bcf. The largest gains in the US came from the Gulf onshore region of Texas and Louisiana where production increased 462 Bcf, largely due to the increase in shale production from the Barnett shale in Texas and Fayetteville shale in Arkansas. Gulf of Mexico onshore drilling in 2007 was up 11% compared to 2006.

Another US region experiencing growth in production is the US Rockies, mainly Wyoming. In 2007, Wyoming increased production by 93 Bcf, or 6%, despite a 7% decline in drilling. The mainstay of Rockies production is from unconventional sources—tight gas and coalbed methane.

Oklahoma, part of the US mid-continent region, increased production 43 Bcf (3%). Shale gas is becoming increasingly important in the mid-continent, namely in Arkansas where shale production is approaching 1 Bcf/d. "Other US" production increased 201 Bcf (5%).

The Canadian Scotian Shelf, which has only one producing project—the Sable Offshore Energy Project—recorded an increase in production of 19 Bcf (15%) in 2007 attributable to the addition of compression designed to temporarily ramp up production levels from existing wells.

■ Regional Supply Declines

The largest production decline was in western Canada, where, in 2007, there was a 178 Bcf (3%) decline, following a 25% decline in drilling. The decline in drilling has been attributed by some to higher production costs, lower prices, and higher provincial royalties in Alberta, which are slated to start in 2009.

Declines in US Federal Gulf Coast Offshore, continued in 2007 with a 68 Bcf (3%) decline in production. Offshore drilling decreased by 15% in 2007.

North American Natural Gas Supply

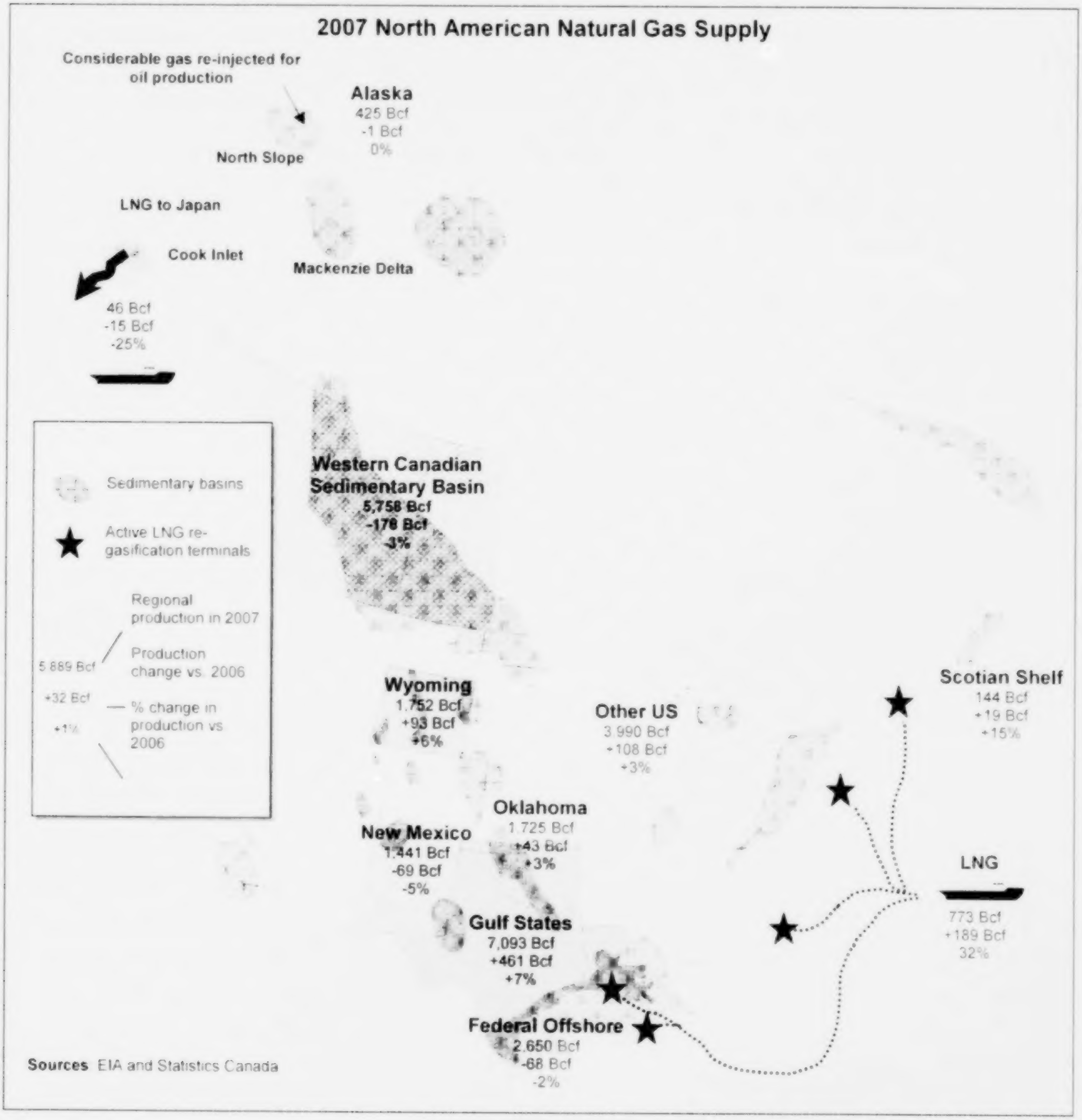
	2007	2006	Change	
	Bcf	Bcf	Bcf	%
Gulf Onshore[1]	7,093	6,631	462	7%
Gulf Offshore[2]	2,650	2,718	-68	-3%
Total Gulf	9,743	9,349	394	4%
Wyoming	1,752	1,659	93	6%
New Mexico	1,441	1,511	-70	-5%
Oklahoma	1,725	1,682	43	3%
Alaska	425	426	-1	0%
Other US[3]	4,050	3,849	201	5%
Total US Production	**19,136**	**18,476**	**660**	**4%**
Western Canada[4]	5,758	5,936	-178	-3%
Scotian Shelf	144	125	19	15%
Total Canada Production[5]	**5,902**	**6,061**	**-159**	**-3%**
Total N.A. Production	**25,038**	**24,537**	**501**	**2%**
US Gross LNG Imports	773	584	189	32%
US Gross Mexican Imports	54	13	41	316%
US Supplementals[6]	61	66	-5	-8%
Total N.A. Supply	**25,926**	**25,200**	**726**	**3%**

Sources: EIA and Statistics Canada

Notes: [1] LA, TX [2] Federal Offshore Gulf of Mexico. [3] EIA expanded "Other US" to include a number of new states. [4] Includes minor Ontario production. [5] Canadian production is marketable gas plus reprocessing shrinkage. [6] Synthetic natural gas, propane-air, refinery gas, biomass gas, air injected for stabilization of heating content, and manufactured gas commingled and distributed with natural gas.

In the US, Alaska and New Mexico recorded declines of one (1) and 70 Bcf respectively. Natural gas production in Alaska takes place at Cook Inlet and is sold in Alaska or exported via liquefied natural gas tankers to Asia.

The following map illustrates major supply regions in North America, and regional supply changes in 2007 compared to 2006.



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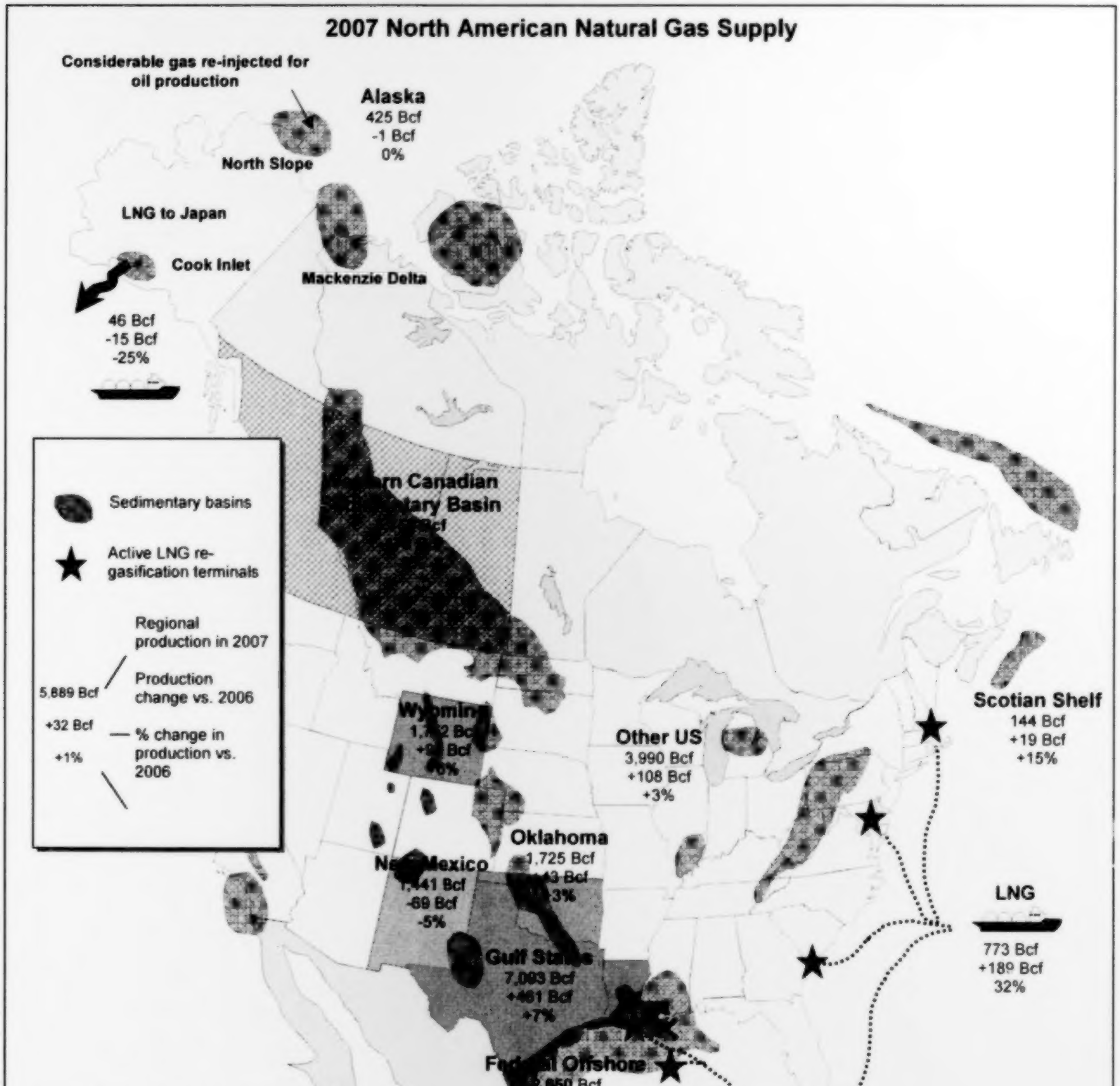


Sources: EIA and Statistics Canada

■ Focus on Drilling and Production

Natural gas drilling in the US and Canada has increased dramatically since 2000. However, in Canada, natural gas drilling levels have been on the decline since 2005, as shown in the table at right and in the following graph.

US gas wells drilled, ramped up from 16,242 wells in 2000, to 32,910 in 2007. In Canada, while drilling has tapered off in recent years, producers still drilled over 12,000 wells in 2007, from roughly 9,000 in 2000. (Note: Drilling peaked at 18,500 in 2005.)

Following years of lacklustre production increases in the US Lower 48, production in 2007 and 2008 rose quickly as producers learned to more effectively extract natural gas from shale gas resources. For the first nine months of 2008, EIA data suggests that US production is up a remarkable 6%, or 3.3 Bcf/d. Such production gains have not been witnessed since the late 1960s.

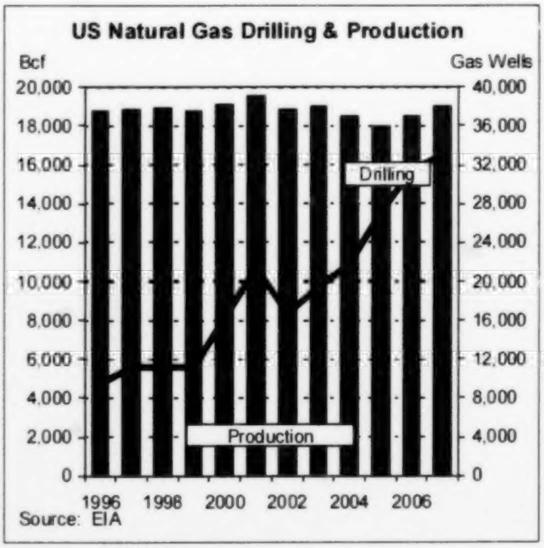
US shale production from the Barnett shale in Texas and the Fayetteville shale in Arkansas has increased rapidly of late. Since 2000, shale production has increased from 1 Bcf/d in 2000 to 3.8 Bcf/d in 2007, and 4.7 Bcf/d in the first half of 2008. Shale production is expected to continue to rise as new shale plays are brought on line.

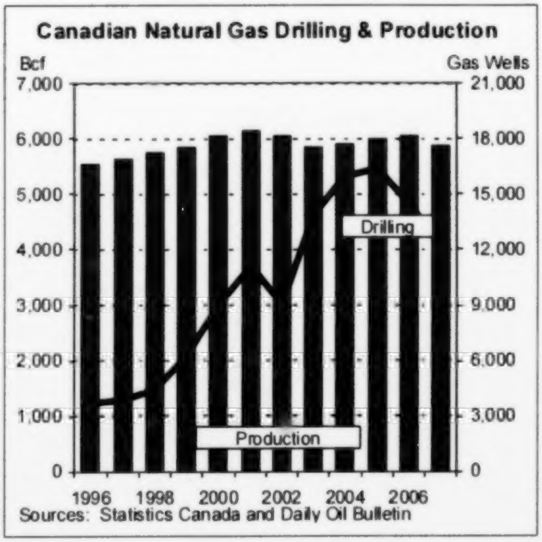
North American Gas Drilling Indicators

	2007	2006	Change #	Change %
Active Oil & Gas-Directed Rigs:				
Gulf Onshore[1]	959	864	95	11%
Gulf Offshore[2]	73	86	-13	-15%
Total Gulf	1,032	942	90	10%
US Mid-continent[3]	247	213	34	16%
US Rockies[4]	299	322	-23	-7%
Other US[5]	191	176	15	9%
Total Oil & Gas-Directed Rigs	**1,769**	**1,649**	**120**	**7%**
Total US Gas Wells Drilled	**32,910**	**31,587**	**1,323**	**4%**
Total Gas-Directed Rigs[6]	**1,466**	**1,372**	**94**	**7%**
Canadian Gas Wells Drilled:				
Shallow	7,032	8,537	-1,505	-18%
Deep	3,248	5,321	-2,073	-39%
CBM	2,052	2,609	-557	-21%
Total Canada	**12,332**	**16,467**	**-4,135**	**-25%**
Total N.A.	**45,242**	**48,054**	**-2,812**	**-6%**

Sources: EIA, NEB, Texas RRC, Baker Hughes, Daily Oil Bulletin
Notes: [1] AL, LA, MS & TX onshore. [2] AL, LA, MS & TX offshore. [3] AR, KS & OK. [4] CO, NM, UT & WY. [5] Remaining US. [6] Average total weekly gas-directed rig count.

Unlike the US, drilling in Canada has fallen off in 2007, particularly in Alberta, where higher





royalties (set to come into effect January 2009), lower gas prices, and rising costs (labour, steel) are impacting producer drilling investments. As a result of less wells, total Canadian production declined 3% in 2007 and continued to fall in 2008. Total Western Canada Sedimentary Basin (WCSB) production was down an average 0.8 Bcf/d for the first eight months of 2008. The previous two graphs illustrate the trends in drilling and production in Canada and the United States.

However, the trend towards unconventional production in Canada is occurring as it did in the US with coalbed methane (CBM) in the 1980s and more recently with shale gas. Currently, producers are extracting both tight gas and CBM from western Canada which, when combined, accounts for approximately 15% of total Canadian production. With respect to shale gas, the majority of activity is taking place in northeast BC where producers are paying record prices for land where shale exists. There is also some shale gas activity occurring in Quebec and Nova Scotia. Commercial shale production is expected in Canada in 2009.

British Columbia Shale Gas

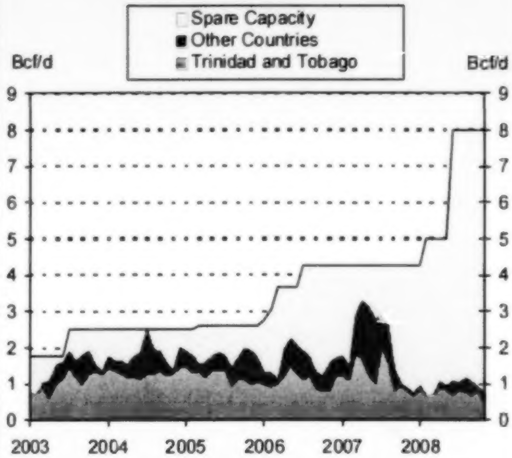
Since 2007, shale gas and tight gas prospects in the Horn River and Montney plays of northeast British Columbia (BC) have attracted significant interest from Canada's upstream natural gas industry. For example, in 2007, the BC Crown took in $1.1 billion in land sales and $2.1 billion in the first eight months of 2008.

Favourable test results reported from initial wells, major interest in land sales and open seasons for new pipeline capacity are all indications of the potential significant impact on production levels from these areas.

Interest in shale gas in Canada follows upon the success of shale gas developments in the US. The largest concentration of interest is occurring in northeast BC, but the early stages of development are also underway in Quebec and the Maritimes.

Commercial development of shale gas is still in its infancy in Canada. Production is currently constrained due to the lack of suitable infrastructure to transport shale gas to major transmission pipelines.

US LNG Imports and Capacity



Sources: EIA, company websites

Overall in North America, as a result of the recent production increases, concerns about future North American natural gas supply have abated considerably.

■ Focus on LNG

In 2007, US gross imports of LNG increased 189 Bcf (32%) to a record 773 Bcf from 2006 levels. This level of LNG imports represented 3% of North American supply. North America (specifically, the US) has imported minor amounts of LNG for many years.

As shown in the figure above, US LNG imports remained fairly flat from 2003 until early 2007, then spiked in response to high US natural gas prices and low global demand for LNG. However, after peaking at nearly 3.5 Bcf/d in mid-2007, US LNG imports fell as global demand for LNG increased and US gas prices fell relative to competing markets in Asia and Europe.

Imports have continued to slump in 2008 despite large additions to US import capacity (which

currently stands at approximately 8 Bcf/d). US terminal operating use or load factor as of mid-2008 was only 15%. This compares to the average terminal usage of 71% in 2005.

With respect to supply, Trinidad and Tobago remain a key source for US LNG, supplying the US with 58% of its LNG imports in 2007. Other major suppliers in 2007 included Algeria (10%), Egypt (15%) and Nigeria (12%). In 2008, the US began importing from the newly commissioned Snøhvit project in Norway.

Other than cargoes from Trinidad and Tobago, which are long term, LNG deliveries to the US are at the discretion of LNG suppliers. When US natural gas prices are high, relative to prices in other LNG demanding regions (e.g. Europe, Asia), more LNG is delivered to the US. Conversely, if other buyers are willing to pay higher prices for the LNG, suppliers will supply those other, more profitable markets first. After the most profitable markets are served, if the LNG supplier has additional LNG supply capacity, it can be sent to the lower priced North American market.

Thus, the amount of LNG delivered to North America depends not only on North American LNG import terminal capacity, but on North American natural gas prices, natural gas or LNG prices in other markets, global LNG production capacity, and other factors.

Given the number of import terminals approved and set to be completed by the end of the decade, it appears that North America will have sufficient LNG import terminal capacity going forward.

In Canada, there are seven proposals to construct LNG import facilities, including three projects in Atlantic Canada, three in Quebec and one in British Columbia. The most advanced terminal is the Canaport terminal being built in Saint John, New Brunswick, which is expected to be operational in 2009. Between 2011-2015, other terminals could be operational. Ultimately, market forces will determine how many facilities will be built in Canada.

In addition, there is one LNG **export** project proposed for Kitimat, British Columbia. In September 2008, the Kitimat LNG project proponents announced their intention to export LNG from Kitimat, British Columbia (BC) to Asian markets where LNG prices are higher. Kitimat's proposal is a complete reversal from their original plan to import LNG to the same location. The original project was fully approved but had yet to begin construction.

Kitimat's decision to pursue LNG exports was based on a combination of its inability to secure a global source of LNG supply for its import terminal and the price arbitrage opportunities offered by Asian LNG markets. Kitimat expects that unconventional natural gas production increases in northeastern BC will act as the feedstock for its liquefaction and export terminal. This reversal of the Kitimat business model is one indication of the current uncertainty about North American LNG imports.

■ Natural Gas Proved Reserves

■ Significance of Proved Reserves Estimates

Proved reserves of natural gas are estimates of the quantities of gas remaining in known drilled reservoirs that are economic to produce and are connected, or can easily be connected, to pipelines and markets. As of year-end 2007 in the US and year-end 2006 in Canada, the combined reserves of the two countries amounts to 296 Tcf, with 238 Tcf in the US and 58 Tcf in Canada. (Note: Canadian reserve data for 2007 is expected to be released in early 2009.)

The year 2007 was historic for the US as net reserve additions were the largest on record at 26.6 Tcf (46.1 Tcf of reserves added minus 19.5

Tcf of production). Total US reserves at year-end 2007 stood at 238 Tcf, 47% higher than their low of 152 Tcf in 1993. Canadian reserves were up marginally to 58.2 Tcf with the largest gains of 0.7 Tcf being recorded in BC and the largest losses at 0.8 Tcf recorded in Alberta.

In 2007, combined US and Canada production was 25.0 Tcf. Thus, the North American reserve-to-production ratio (R/P ratio) was 11.9 years, up from 10.4 in 2006. In other words, if no new gas reservoirs are found, US and Canadian reserves would last nearly 12 years at current production rates.

Of course, new reserves are found every year. Every year, proved reserves change, according to the following formula: proved reserves at start of year + reserve additions (including revisions, whether positive or negative, to previous estimates) during the year - production during the year = proved reserves at end of year.

Proved reserves estimates provide a good basis for estimating future natural gas production levels in an area. There are several relationships between reserves and production that are commonly seen. These include:

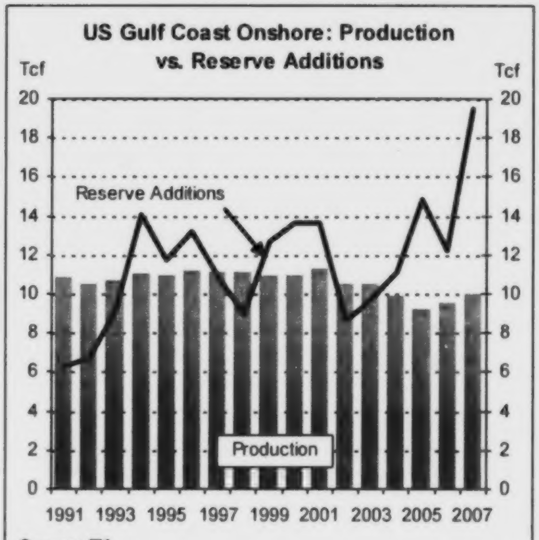
- Where proved reserves are high relative to production, as indicated by a high (e.g., greater than 12 years) R/P ratio, production generally increases;
- Rising proved reserves are generally correlated with rising natural gas production; and
- Falling proved reserves are generally correlated with falling natural gas production.

From 1990 to 2007, Canadian and US reserves and reserves to production ratios have been fairly stable and rising slightly in the last half decade. However, in 2007, due to favourable economics and technological advancements in drilling and hydraulic fracturing (or "fracing"), US producers were able to add significant amounts of unconventional natural gas resources to reserves.

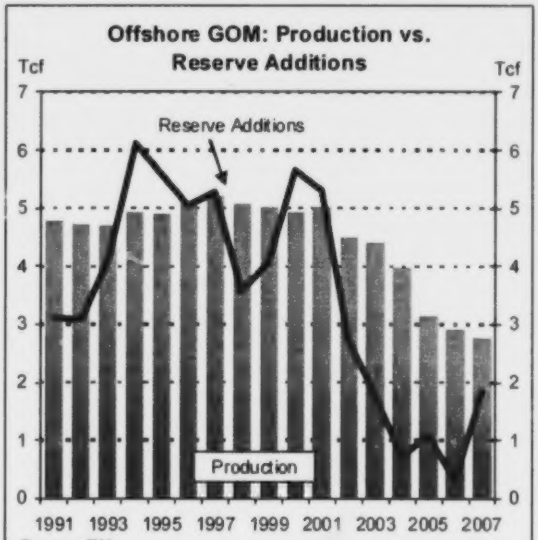
We have divided Canada and the US into major supply areas: western Canada, US Gulf Coast onshore, US Gulf Coast offshore, Wyoming and Oklahoma.

■ **Gulf Coast: Onshore and Offshore**

Of the supply areas defined here, the Gulf Coast is by far the largest, accounting for 39% of North American gas production in 2007. Following are



Source: EIA



Source: EIA

two graphs—one for the Gulf Coast onshore and one for the offshore region.

As shown, Gulf onshore production (includes Texas and Louisiana) and reserves are rising. In 2007, reserve additions skyrocketed to almost 20 Tcf and there was a 7% increase in production. The onshore Gulf Coast reserve additions and production increases are dominated by increased unconventional production in Texas. Unconventional production in Texas includes shale gas from the Barnett shale play and tight gas from the Cotton Valley Formation. In fact, the Newark East field in the Barnett shale formation may soon become the largest natural gas field in the US.

Conversely, in the Gulf Coast offshore, production and reserve additions continue to decline. However, as production continues to decline (from over five (5) Tcf in 2000 to less than three (3) Tcf in 2007) year-over-year declines have less of an impact on total US production volumes.

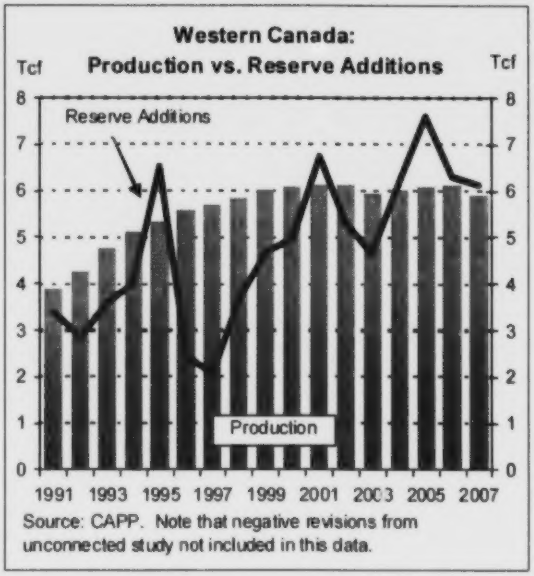
■ Western Canada

Natural gas production from Canada's western provinces of British Columbia, Alberta and Saskatchewan accounted for nearly a quarter of North American production in 2007.

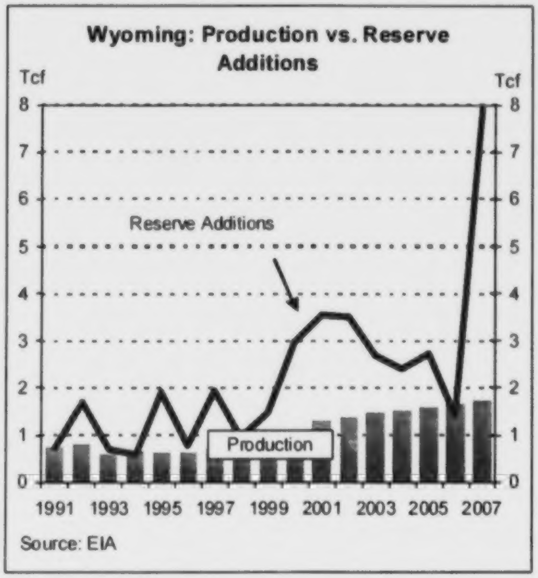
In recent years, western Canada reserve additions have varied, but have roughly kept pace with production. Both production and reserve additions appear to have stabilized in the six (6) Tcf per year range.

However, this has only been achieved by a dramatic increase in drilling over the 1990-2007 period. There were 1,500 western Canadian gas wells drilled in 1996, and over 12,000 in 2007. Note: Drilling is down from the peak of 18,000 wells in 2005 due to lower prices and changes to the Alberta royalty structure. The decline in drilling continued in 2008 as prices remained at lower levels than 2005 and 2006.

A bright spot for western Canadian reserves is shale gas development in northeastern BC. While still in its infancy, shale gas offers the potential to add significantly to reserves and production from western Canada post 2010.



Source: CAPP. Note that negative revisions from unconnected study not included in this data.



Source: EIA

■ Wyoming

As shown in the previous graph, with the exception of 2006, natural gas reserve additions in Wyoming have been greater than production

each year since 1991. In 2007, Wyoming's natural gas reserves levels surged as producers added eight (8) Tcf of reserve additions, four times annual production levels, and the highest reserve addition on record for the state.

The growing reserves in the US Rockies region—Colorado, Utah, and Wyoming—are being driven by additions from unconventional sources including CBM and tight gas. The Rockies are the third largest natural gas supply area in North America and accounted for approximately one fifth of North American production in 2007.

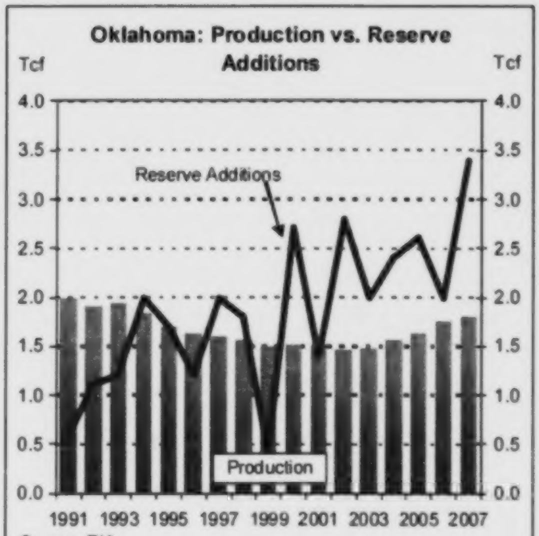
In recent years, not only have reserve additions far exceeded production but proved reserves levels have increased. Given that reserve additions in Wyoming alone were nearly eight (8) Tcf in 2007 and production is less than two (2) Tcf, production in the area could continue to rapidly grow.

■ Oklahoma

In 2007, Oklahoma accounted for about 7% of North American gas production. Production in the mid-continent—Arkansas, Kansas and Oklahoma—fell steadily over the 1991 to 2002 period and, implying further production declines, reserve additions were less than production. However, since 2000, reserve additions have exceeded production and beginning in 2004 production began to rise. The area has recently seen high activity in the Woodford shale which may explain the change.

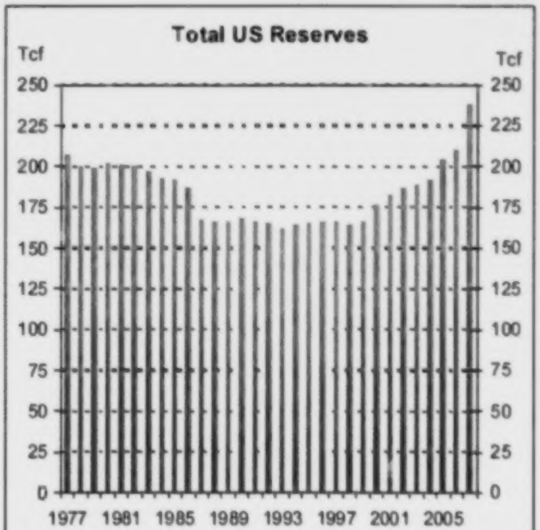
■ Total US Reserves

Since 1999, US reserves have increased each year, reversing the previous trend of declining reserves. US natural gas reserve growth is primarily due to unconventional natural gas. In the past, these large resource plays were known but could not be produced economically nor added to reserves. However, with new drilling and completion technologies, these new unconventional resources are beginning to be converted to proved reserves.



Source: EIA

Shale gas is receiving significant attention given the successes in the Barnett shale in Texas and other shales in the mid-continent. In the two years the EIA has collected data on shale gas reserves, shale gas reserves have increased 50% and now account for 9% of total US reserves.



Source: EIA

■ Coalbed Methane

CBM has been produced in the US since the 1980s. Production and resources are focussed in the Rockies, New Mexico and the Midwest, with smaller amounts in various eastern states. Production of CBM has risen steadily since the late 1980s and has been supported by significant growth in reserves.

For example in 2000, US CBM reserves were 15.7 Tcf and production was 1.37 Bcf/d. In 2007, reserves increased to 21.8 Tcf (up 38% since 2000) and production averaged 4.8 Bcf/d (up nearly 30% from 2000). CBM reserves account for 9% of total US dry gas reserves while CBM production accounts for 9% of total US natural gas production.

■ North American Natural Gas Storage

North American natural gas production is fairly constant throughout the year. However, total demand in peak winter periods can surpass periods of low summer demand three-fold, and core—residential and commercial—winter demand can be six times higher than core summer demand. To bridge the seasonal gap between supply and demand, natural gas is injected into storage in the summer, and withdrawn in the winter.

Local distribution companies (LDCs) inject gas into storage, and withdraw it in winter to meet peak winter demand loads in the residential and commercial sectors. Storage also allows LDCs to use contracted, long-haul pipeline capacity at relatively stable rates all year.

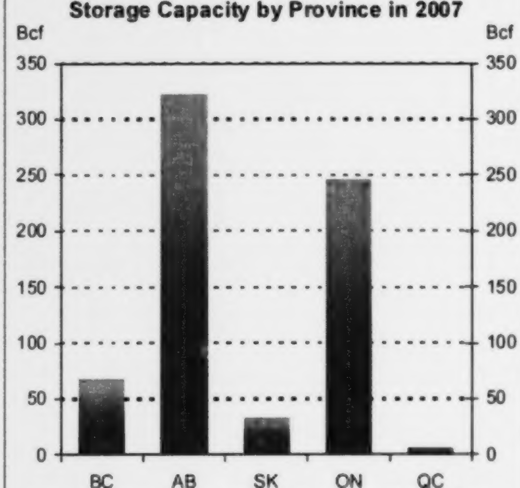
Producers use storage injections or withdrawals to balance fluctuating production levels with contractual supply obligations. Storage is also used by both buyers and sellers of natural gas to capture price arbitrage opportunities (i.e. inject natural gas into storage when prices are low, and withdraw natural gas and sell it when the price is higher).

The typical storage inventory pattern for all of North America is for storage levels to peak at about 3.8 Tcf in late October/early November, and bottom out at about 1.4 Tcf in late March/early April.

North America has approximately 4.5 Tcf of storage capacity (3.7 Tcf in the US, and 0.7 Tcf in Canada). Natural gas is stored primarily in underground depleted oil and natural gas reservoirs, or salt caverns. However, approximately 3% of storage is above ground, in liquefied natural gas (LNG) tanks.

■ Canadian Storage

As illustrated in the graph below, storage in Canada is spread across all regions. The majority of storage is located in western Canada (424 Bcf), with Alberta having the greatest storage volume, and smaller storage capacity in the other producing provinces, BC and Saskatchewan. Western Canadian storage is used primarily for managing supply and



Source: Various storage companies, calculated by NRCan. AB storage includes non-commercial storage facilities.

demand. Storage in eastern Canada (253 Bcf) is located primarily in Ontario. This large volume of gas in storage helps to meet Ontario's high demand in peak periods.

■ Natural Gas Storage & Price Relationship

Storage levels play a very large role in natural gas prices. Traditionally, there is an inverse relationship between natural gas storage levels and prices. Considering the time of the year, high storage levels promote lower prices, and lower storage levels promote higher prices.

The graph following (at left) illustrates natural gas prices and the difference between actual storage in each month, and a five-year average storage level for that month. The difference is then smoothed using a three (3)-month moving average to remove any monthly spikes and to highlight seasonal storage trends. The large price spike that occurred in late 2005 was the result of Hurricane Katrina disabling US Gulf Coast production and causing a storage shortfall. When production restarted, storage levels, helped by a warm winter, increased and prices stabilized.

Between 2006 and 2008, above average storage levels were the norm. A cold winter brought about lower than average storage in early 2008 and prices spiked. However, cooler summer weather lowered demand for natural gas. This resulted in a return to above average storage levels in the second half of 2008 and prices retreating to more moderate levels.

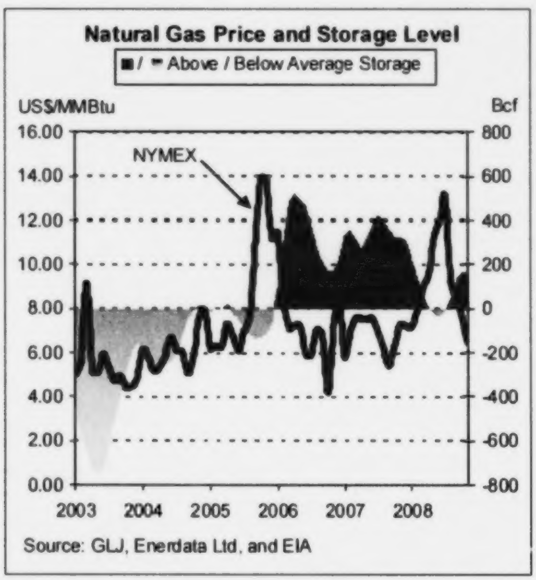
■ Summer 2007 & Winter 2007/08

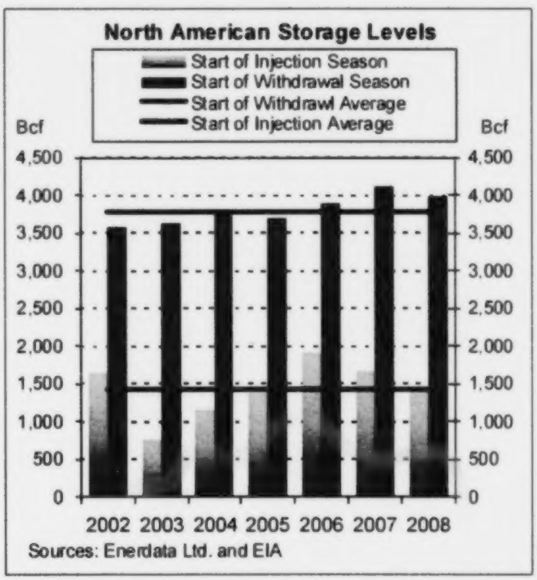
The start of the summer 2007 injection season saw North American storage levels at 1.7 Tcf. Approximately 2.4 Tcf was injected into storage over the summer which resulted in record levels of 4.1 Tcf of storage at the start of the 2007/08 withdrawal season (November 1, 2007).

A colder than expected winter resulted in storage falling to its lowest volume in the past three years, at 1.4 Tcf at the start of the 2008 injection season (April 1).

■ Summer 2008 Injection Season

At the start of the injection season, prices were relatively high. A cooler than expected summer, combined with increased shale gas production in the US, resulted in large volumes of gas (approximately 2.6 Tcf) being injected. As storage levels rose quickly, prices fell. On November 1, 2008, total North American storage





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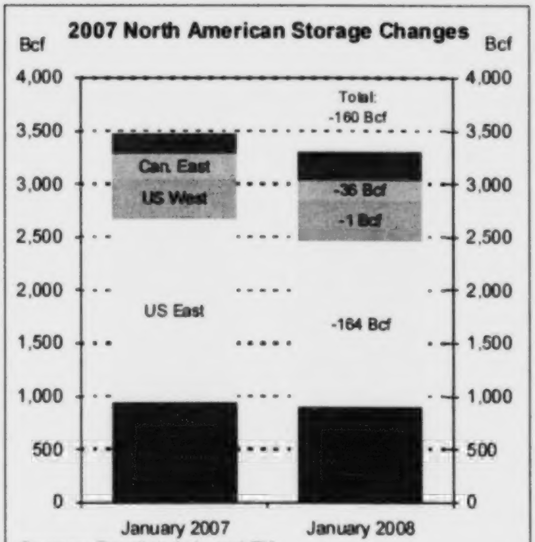
levels were at near capacity (4.0 Tcf), and only slightly below the record storage levels set in 2007.

■ Winter 2008/09 Storage Outlook

With storage levels being above average once again, this should have a mitigating effect on price movements over the course of the 2008/09 heating season. In combination with the potential for a warmer than average winter, there could be strong downward pressure on natural gas prices. As is always the case in the heating season, weather plays the role of the 'wild card'.

■ Storage Inventory Changes

In the 2007 calendar year, North American storage volumes fell from 3.5 Tcf on January 1, 2007 to 3.3 Tcf on December 31, 2007, a decline of 160 Bcf. This represents a decline of 5% for the year. While this change is not that important for market dynamics, it is important for reconciling different North American natural gas supply and demand levels over the calendar year. In 2007, demand was greater than supply, which led to this 160 Bcf drawdown in storage levels.



Sources: Enerdata Ltd., and EIA

The previous graph illustrates the changes in storage volumes in each region. The largest absolute decline (164 Bcf) occurred in the east region of the US, while eastern Canada saw a 16% decline in volumes. Only western Canada had storage volumes increase in the 2007 calendar year.

■ North American Natural Gas Prices

Every day, in various natural gas markets around North America, thousands of buyers and sellers interact electronically or by phone and agree on a sale price for natural gas. Prices are unregulated, and fluctuate according to buyer and seller perceptions of supply and demand fundamentals. These fundamental factors can be short-term in nature (e.g. weather and demand today) or longer-term (e.g. expected cost of finding new natural gas over the next five years).

The various regional natural gas markets are linked by pipelines and are subject to similar continental market forces. Because of this, Canada, the United States, and to a lesser extent Mexico, make up a large, integrated North American natural gas market. Prices in the various regional markets generally track each other.

The map on the following page provides average annual natural gas prices at various producing basins, market hubs, consumption markets and export points in North America. Prices reflect simple 12-month averages except for export points, which are volume-weighted 12-month averages.

Average natural gas prices in 2007 were from 2% higher to 31% lower than average 2006 prices. These lower prices reflect the fact that the winter months in 2007 were warmer than average, and an absence of supply disruptions

Canada

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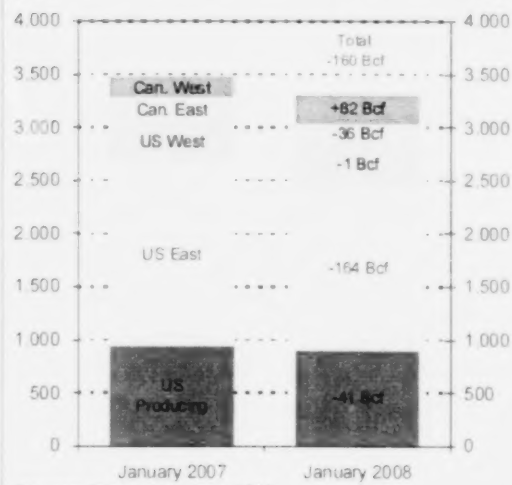
2007 North American Storage Changes



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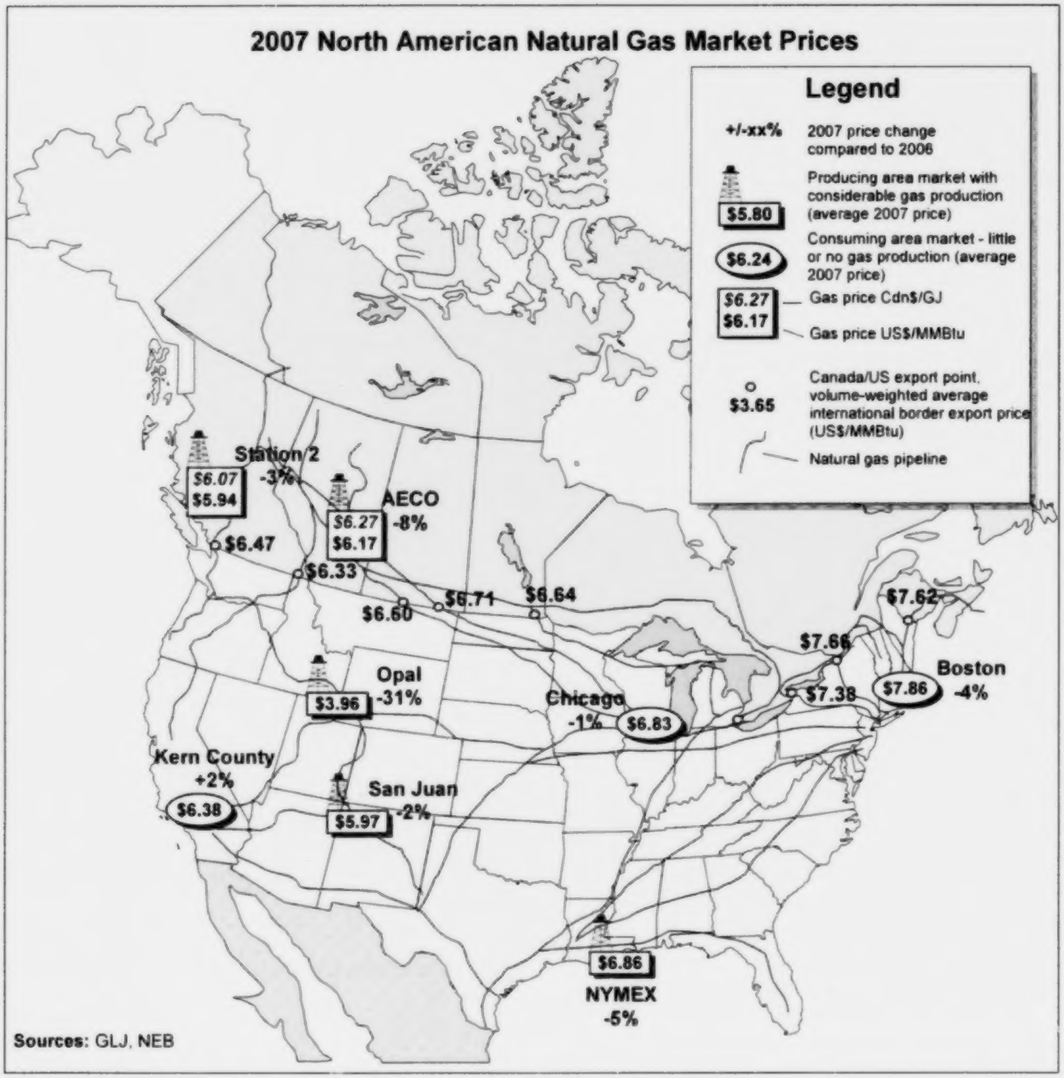


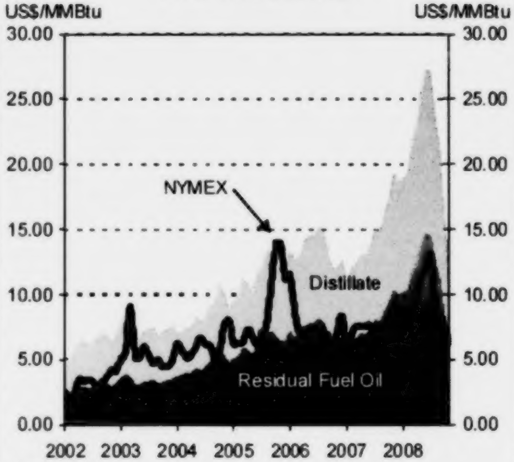
caused by weather events such as Gulf Coast hurricanes. Only prices recorded at Kern County, California—rising by only 2%—were higher in 2007.

Arguably, the two most important markets in North America are the Intra-Alberta and Henry Hub markets. The Alberta market has the largest volume in terms of gas physically exchanged, with an average of 11 Bcf/d flowing through the hub. With only two (2) Bcf/d of physical gas flows, Henry Hub is the reference delivery point for the NYMEX natural gas futures market. The Henry Hub sees the highest volume of total trades. Most of these trades do not result in the physical delivery of gas.

■ Crude Oil Influence on Natural Gas Prices

Crude oil and petroleum products are substitutes for natural gas, particularly in the longer-term. Some amount of fuel-switching does regularly occur at industrial and power generation facilities between natural gas and petroleum products. As a result, when oil prices rise, users try to switch to natural gas to escape the high

Petroleum Products and Natural Gas Price Relationship



Source: GLJ

fuel costs. This drives up natural gas demand, which drives up natural gas prices. This dynamic has typically meant that North American natural gas prices were strongly influenced by world crude oil prices and North American petroleum product prices.

In previous years, North American natural gas prices (e.g., the NYMEX Henry Hub price) varied within a price band set on the low end by the price per MMBtu of residual fuel oil, and on the high end by the price per MMBtu of distillate. As can be seen in the previous figure, from 2002 through early 2006 this relationship was strong.

However, natural gas and oil prices have recently decoupled from each other. Rapidly rising oil prices, combined with high natural gas storage inventory levels, resulted in natural gas prices falling below the petroleum product price band for most of 2006 and 2007. In 2008, natural gas prices remained below the lower band, despite the dramatic price increase witnessed in July 2008 due to natural gas prices playing 'catch-up' with crude oil prices.

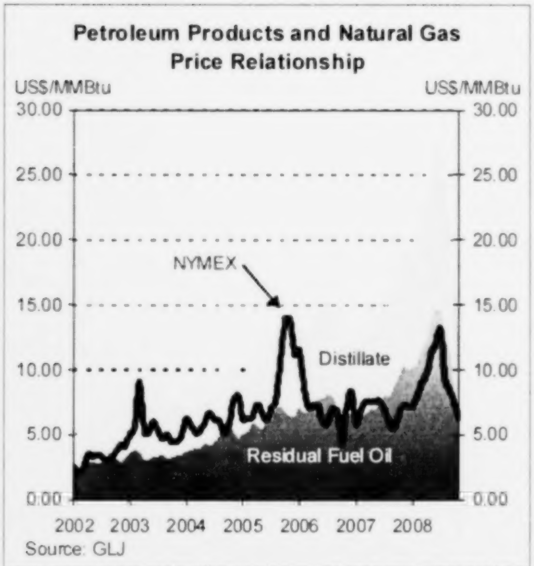
Analysts often compare the price of crude oil per barrel (bbl) with the price of natural gas per MMBtu. Based on the heat content of these two fuels, the ratio of their prices should be close to six (6) to one (1). Over the previous five years, this ratio was roughly eight (8) to one (1). In 2006, WTI crude averaged US$66.07/bbl, and NYMEX natural gas prices averaged $7.23/MMBtu—a ratio of nine (9) to one (1). In 2007, this average rose to 10.5 to one (1). The ratio continued to increase into 2008, with year-to-date (as of November 2008) WTI averaging US$104.88/bbl and NYMEX natural gas averaging US$9.23/MMBtu, the ratio was 11.4 to one (1). This high ratio indicates that crude oil is overpriced relative to natural gas, strictly on a heat content basis.

■ Regional Natural Gas Prices

Each regional natural gas market has its own supply, demand, and price dynamics. Natural gas prices are usually lowest in the supply basins of Alberta and the US Rockies. This reflects the fact that these markets have much more supply than demand, and are a long distance (high pipeline transportation costs) to higher priced markets. Consuming markets that are far from producing regions, such as Boston for example, have the highest prices. This reflects the transmission costs associated with moving natural gas to these distant markets.

As the figure on the following page indicates, most North American natural gas markets are strongly integrated and generally, prices track each other. Provided there is enough pipeline capacity linking markets, demand or supply can be transferred from one market to another causing price linkages. In this integrated situation, the difference in prices between regions is roughly equal to the cost of natural gas transmission between the regions.

The US Rockies region is characterized by the lowest natural gas prices, and is decoupled from the rest of the North American natural gas market. The Rockies region has abundant tight gas resources which have undergone development in the past few years. However, because of this rapid natural gas production growth, pipeline capacity is insufficient. This means that because some production in the Rockies region cannot get out of the area, a local oversupply of natural gas has been



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created. This strong competition from suppliers places heavy downward pressure on prices. This is especially true at the Opal Hub in Wyoming. Buyers outside of the Rockies cannot access additional Rockies supply, and, as a result, in 2007 prices at Opal averaged US$3.96/MMBtu, a 31% decline from prices in 2006. In 2008, prices at Opal averaged US$6.26/MMBtu—considerably lower than the 2008 annual average Henry Hub price of US$9.04/MMBtu.

In June 2008, the 1,150 km west leg of the Rockies Express Pipeline (from Colorado to Missouri) was put into operation with approximately 1.4 Bcf/d of gas flowing through it. The 1,025 km east leg has had problems with construction and regulatory delays, and full operation has been delayed until November 2009.

When completed, the Rockies Express Pipeline will transport 1.8 Bcf/d of Rockies gas to markets in the eastern United States. This should narrow the gap between prices in the Rockies and at Henry Hub.

■ Natural Gas Prices in 2008

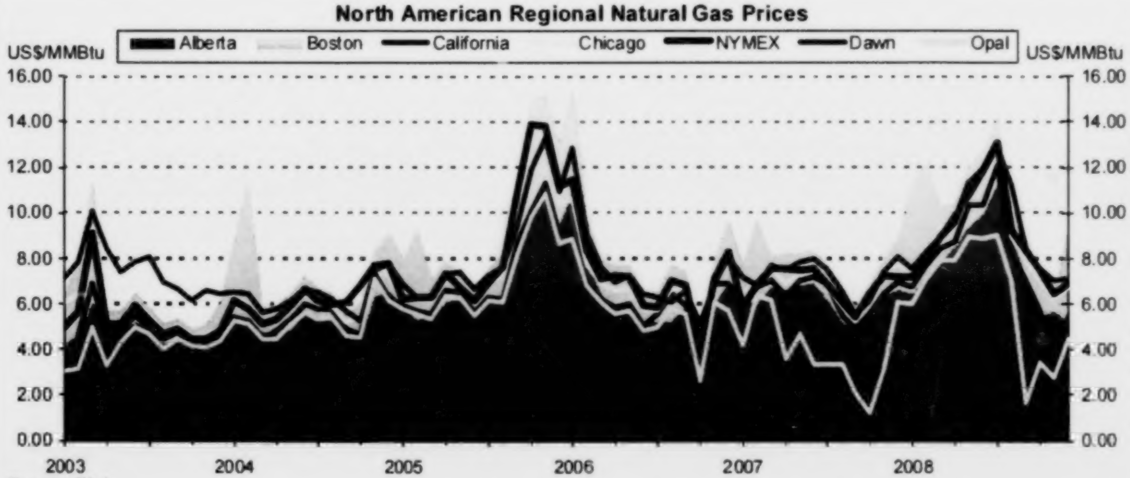
Natural gas prices were extremely volatile in 2008. The year started with relatively stable prices, averaging levels that were typical in recent years. A cold winter and the resultant drawdown in storage brought about higher prices by March and April. The large volume of storage withdrawn over the winter months, and the low levels at the start of the injection season continued to place upward pressure on prices during summer 2008.

Further contributing to rising natural gas prices was the increase in all energy commodity prices (speculation has been suggested as a cause for this increase), particularly the price of crude oil, which peaked at US$145/bbl (daily spot price) in July 2008. Also in July 2008, the NYMEX natural gas price spiked at US$13.11/MMBtu—an 83% increase from the January 2008 price.

Heading into autumn, natural gas prices began a rapid decline due to several factors. First, the realization that US production was rising fast—US production from January to September was up 6% compared with the same period in the previous year. Second, the financial crisis led to reductions in demand expectations, which not only affected natural gas prices, but oil and other commodity prices as well. By December, the NYMEX price was US$6.89/MMBtu—a 47% decline in only five (5) months.

The average Intra-Alberta natural gas price for 2008 was $7.73/GJ, a 23% increase from the 2007 annual average.

North American Regional Natural Gas Prices



Source: GLJ

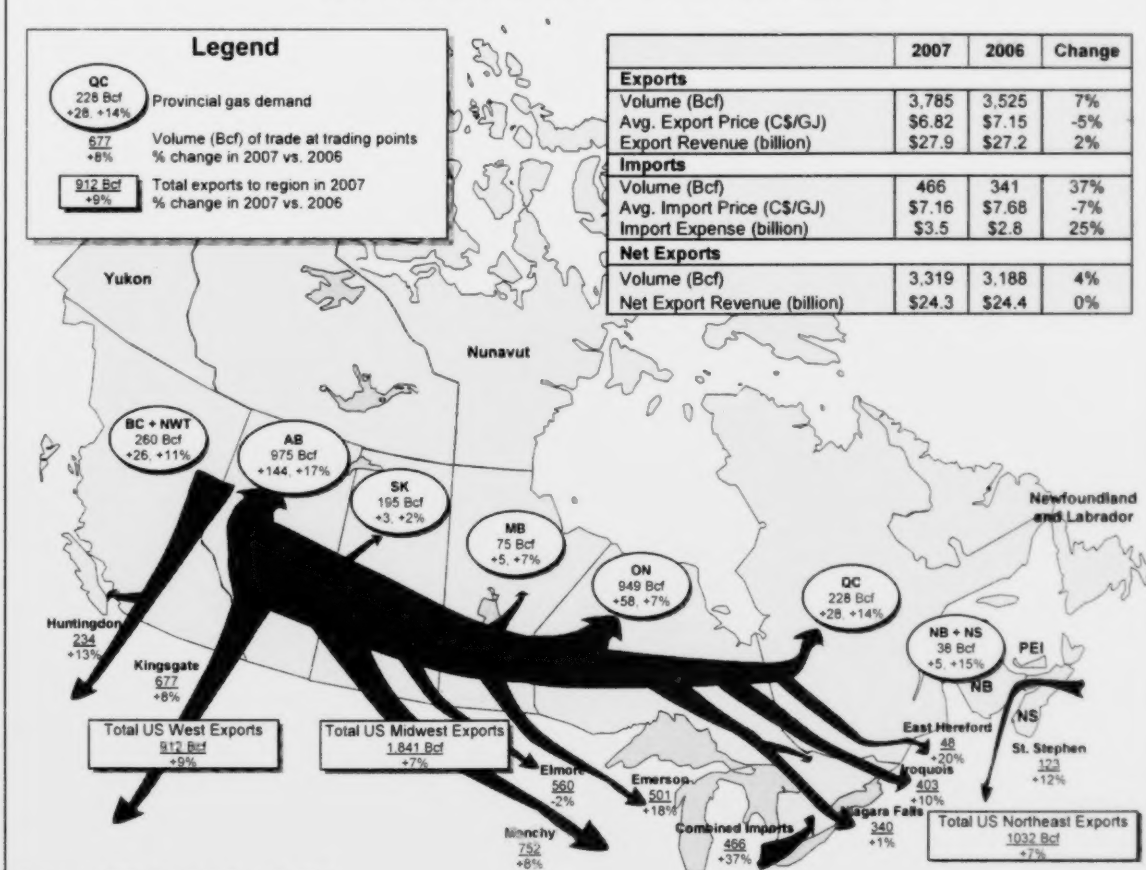
■ Natural Gas Exports, Imports, & Revenues

The following map shows provincial natural gas demand in 2007 in Bcf, the positive or negative change in demand, the percentage change in demand, the volume of gas exported (gross) at each international border export point, and the percentage change in exports. Total gross exports to each of the major US export regions are also given. The table within the map shows the calculation of gross and net exports, as well as the value of natural gas exports as calculated at the international border. Note: The value of exports at the plant gate will be less.

■ 2007 Exports

Export prices were lower, but volumes and revenues (at the international border) were both higher in 2007 compared to 2006. Gross export volumes reached record levels in 2007 at 3,786 Bcf—an increase of 260 Bcf, or 7% from 2006 volumes. These higher volumes, despite lower export prices—down 5% at $6.82/GJ—led to a slight increase in international border export revenues—up 2% to $27.9 billion.

2007 Natural Gas Trade and Provincial Demand



	2007	2006	Change
Exports			
Volume (Bcf)	3,785	3,525	7%
Avg. Export Price (C$/GJ)	$6.82	$7.15	-5%
Export Revenue (billion)	$27.9	$27.2	2%
Imports			
Volume (Bcf)	466	341	37%
Avg. Import Price (C$/GJ)	$7.16	$7.68	-7%
Import Expense (billion)	$3.5	$2.8	25%
Net Exports			
Volume (Bcf)	3,319	3,188	4%
Net Export Revenue (billion)	$24.3	$24.4	0%

Sources: NEB, Statistics Canada, GLJ

Export and Import Volumes by Export Point							
	2003	2004	2005	2006	2007	07 vs 06 Change	
	Bcf					Bcf	%
Huntingdon (Westcoast)	304	263	272	208	234	26	12.5%
Kingsgate (TransCanada)	562	674	601	626	677	51	8.1%
Total US West	**866**	**937**	**873**	**834**	**911**	**77**	**9.2%**
Monchy (TransCanada)	763	759	712	695	752	57	8.2%
Emerson (TransCanada)	362	417	457	426	501	75	17.6%
Elmore (Alliance)	567	565	587	570	560	-10	-1.8%
Miscellaneous	24	35	32	36	28	-8	-22.2%
Total US Midwest	**1,716**	**1,776**	**1,788**	**1,727**	**1,841**	**114**	**6.6%**
Iroquois (TransCanada)	326	326	365	367	403	36	9.8%
Niagara Falls/Chippawa (TransCanada)	369	376	436	417	428	11	2.6%
St. Stephen (MNP)	130	119	136	110	123	13	11.8%
Miscellaneous	77	69	91	71	78	7	9.9%
Total US Northeast	**902**	**890**	**1,028**	**965**	**1,032**	**67**	**6.9%**
Total Gross Exports	**3,481**	**3,603**	**3,689**	**3,526**	**3,785**	**259**	**7.3%**
Total Canadian Demand	3,574	2,545	2,472	2,452	2,656	204	8.3%
Imports to Canada	437	441	377	342	466	124	36.3%
Total Net Exports	**3,044**	**3,162**	**3,312**	**3,184**	**3,319**	**135**	**4.2%**

Source: NEB

Note: Net exports to the US are equal to gross exports less gross imports.

Gross exports peaked in December 2007, when 370 Bcf of natural gas was exported to the United States—an 18% increase from volumes exported in December 2006.

Net exports in 2007 represented about 56% of total gas produced in Canada. Since 2001, net exports have typically accounted for 55% to 60% of total Canadian production.

■ 2008 Exports

Using data that was available at the time of the publication of this report, natural gas gross exports for the first three quarters of 2008 were 2,748 Bcf, 52 Bcf (or 2%) lower when compared with the first three quarters of 2007.

■ Regional Export Volume Trends

On a regional level, exports grew 7-9% across all US markets. Details on export and import volumes are provided in the preceding table.

Exports to the US west led export growth, up 9.2% in 2007, compared with the previous year. Exports at Huntingdon, BC were 12.5% higher, due largely to demand from power generation on the US west coast. Low water supplies contributed to reduced hydro generation in California and resulted in higher demand for natural gas.

In other markets, such as the US Midwest and US northeast, colder winter months in 2007, relative to 2006, increased the demand for natural gas for heating during the cooler seasons. Exports to these regions increased 6.6% and 6.9% respectively.

The single export point with the largest volume gain was Emerson, MB with an 18% increase in volume. Emerson is located at the border-crossing south of where the TransCanada mainline bifurcates into lines running through northern Ontario, and other lines running south into the US Midwest. Some of this gas exported through Emerson is consumed by the Midwest market, and some is imported into Canada through import points in southern Ontario.

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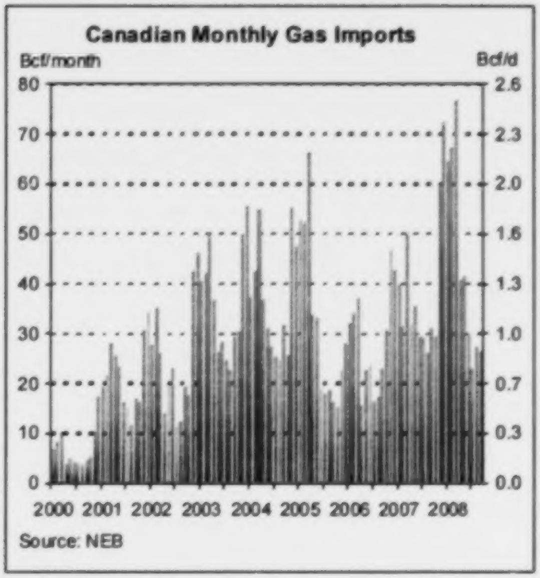


compression at the Sable Offshore Energy Project (Sable). Production from Sable began in 2000, and peaked in December 2001, at nearly 590 million cubic feet per day (MMcf/d). Since then, Sable production has been declining. In 2007, Sable produced 144 Bcf, up from 125 Bcf in 2006. Most Sable gas is exported to the US via the St. Stephen export point. In 2007, about 85% of Sable's production was exported to the US, with the remaining 15% consumed in Nova Scotia and New Brunswick.

■ Canadian Gas Imports

Imports into Canada were at a record 466 Bcf in 2007—a 36.3% increase over 2006 import levels. Furthermore, some of the gas exported from Canada is imported back into Canada. Natural gas imports have been increasing over time, as purchasers of natural gas in consuming markets such as Southern Ontario find it cheaper to access natural gas from the United States.

Currently, all of Canada's natural gas imports are from the United States via pipelines located in southern Ontario. Canada's major import points, Courtright (Vector), Sarnia (Great Lakes Gas Transmission) and St. Clair (Michigan Consolidated) are in southern Ontario, across the border from Detroit. With the completion of the Vector pipeline, imports into southern Ontario grew rapidly starting in 2001.

However, starting in 2009, Canada is expected to begin importing LNG at the Canaport terminal in Saint John, New Brunswick. Canaport has a regasification capacity of 1.0 Bcf/d, and approximately 75% of this imported LNG is expected to be re-exported as natural gas to markets in the northeast United States.

The preceding graph indicates the volatility of Canadian imports, as well as clearly indicating a seasonal pattern. Import volumes in the past have typically doubled during the cooler months to meet peak Ontario and Quebec heating demands. Total imports between April and September 2007 were 183 Bcf, and total imports between October 2007 and March 2008 were 370 Bcf.

The graph also illustrates the increasing trend for gas imports. In 2000, only 83 Bcf of natural gas was imported into Canada. In 2007, this volume reached 466 Bcf—an average increase of 28% per annum.

■ Domestic and Export Plant Gate Revenues

The table located in the map on page 23 calculates export revenues and import expenses using natural gas prices at the international border. However, these prices include certain pipeline transmission costs, and while they reflect the value of the natural gas industry to Canada's balance of trade, they can overstate revenues received by producers who export natural gas.

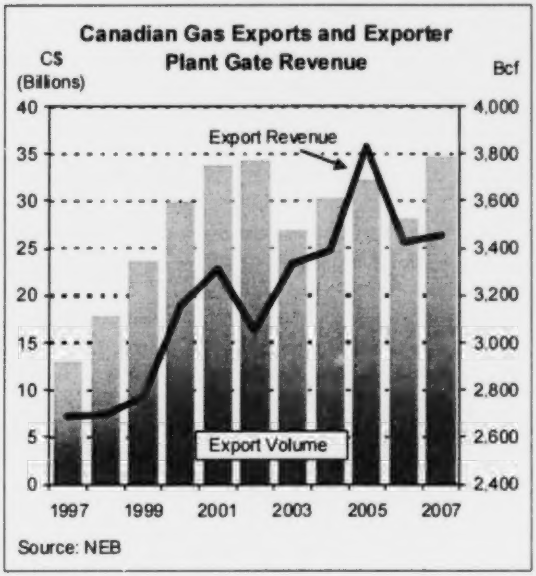
A better indication of revenues received by producers can be calculated by using the plant gate price (i.e. the price of natural gas as it exits a natural gas processing plant).

Using the plant gate price, export revenues (valued at the plant gate) rose modestly in 2007, largely on account of record high gross export volumes of 3,785 Bcf (up 7% from 2006). The graph at top right on the following page illustrates the volume of natural gas exports and

export revenues based on plant gate prices. Total export revenues at the producing plant gate for 2007 were $26.4 billion—3% higher than 2006 revenues, but 26% lower than the record $35.7 billion in plant gate revenues recorded in 2005.

For producer plant gate revenues from domestic sales, the volume—total Canadian gas demand minus gross imports—was multiplied by a weighted average of annual plant gate prices from BC, Alberta, Saskatchewan, and Nova Scotia. In 2007, the average plant gate price was calculated at $6.10/GJ, a 7% drop from the 2006 plant gate price of $6.55/GJ.

Offsetting lower natural gas netbacks, volumes sold to Canadian domestic markets rose by 7%. Therefore, revenues from domestic sales in 2007 were $14.7 billion, unchanged from domestic revenues in 2006.



Total export and domestic sales producer revenues at the plant gate for 2007 were $41.1 billion, up 2% from $40.3 billion in 2006.

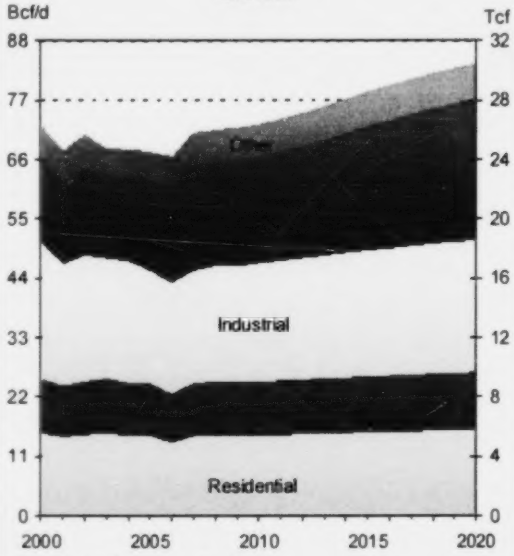
Outlook to 2020

■ North American Natural Gas Demand

In this section, for each variable (e.g. production, demand, prices, etc.) discussed, three to five forecasts from a variety of respected sources such as consultants and government agencies were used to obtain a "consensus view" of the outlook for that variable to 2020. The consensus forecast is calculated using a simple, unweighted average of each individual forecast. In some graphs, the maximum and minimum forecasts are displayed to indicate the range of individual views.

The individual forecasts used for the calculation of each consensus view were published between August and November 2008. These individual long-term forecasts are typically published only once a year, though some consultants update their forecasts biannually, or quarterly. Each individual forecast used was the most recent at the time of the publishing of this report. It is worth noting that 2008 has been typified by volatile financial and commodity markets and ongoing dramatic changes in future expectations.

North American Natural Gas Demand Growth



Sources: Various consultants
Notes: Represents an average view of forecasts from various organizations.

■ Total North American Gas Demand

The figure on this page displays North American natural gas demand growing from 26.1 trillion cubic feet (Tcf) in 2008 to 30.6 Tcf in 2020, and indicates a growth rate of 1.3% per annum. This year's consensus forecast for demand in 2020 is 1.2 Tcf higher than last year's consensus forecast.

Natural gas is the fuel of choice for residential and commercial customers in both Canada and the US. Demand for natural gas by these two sectors is forecasted to be relatively flat, largely due to continued replacement of older natural gas systems by newer more efficient units. Continued efficiency improvements have resulted in a decline in natural gas use per customer, especially in markets with the oldest housing stocks, such as the US Midwest and US mid-Atlantic.

Economic growth and increases in natural gas demand for electric power are key market drivers over the forecast period. Natural gas use to fuel electric power generation in the US is forecast to rise from 6.8 Tcf in 2008 to 9.1 Tcf in 2020, and accounts for about 66% of the increased demand in the US throughout the forecast period and 51% of the increased demand for North America. Industrial demand in the US rises slightly over the forecast period by 0.4 Tcf to 7.2 Tcf.

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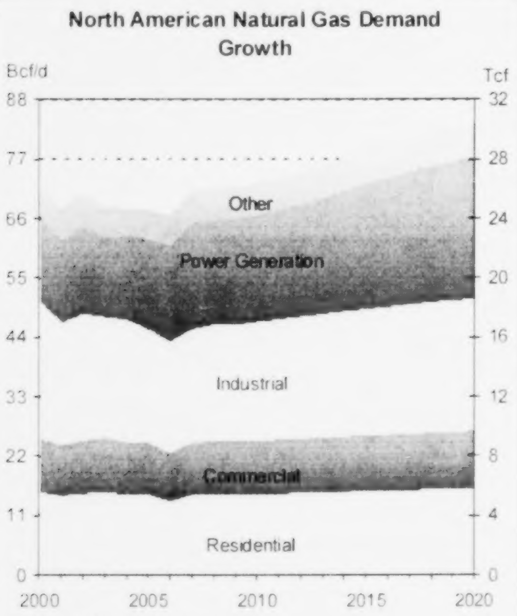

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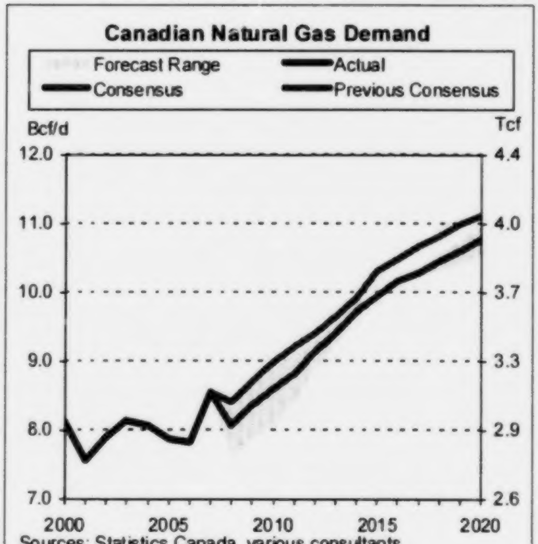
■ Focus on Canadian Demand

The consensus forecast for natural gas demand for Canada is shown in the graph on this page. Using the average of these forecasts, demand would rise from 2.9 Tcf in 2008 to 3.9 Tcf in 2020, an average annual increase of about 2.3%. The consensus forecast is largely unchanged from last year's forecast, where Canadian demand equalled 4.0 Tcf in 2020. Individual forecasts from each consultant show very little variation—3.9 Tcf is the lowest forecast demand, and 4.0 Tcf is the highest.

The projection shows natural gas demand in the industrial sector (including oil sands production) in Canada increasing by 0.66 Tcf from 2008 to 2020, largely because of increased demand by oil sands operators in Alberta. This represents a 50% increase over last year's forecast of a 0.44 Tcf increase in industrial demand. In addition to oil sands and oil refining operations, the industrial sector includes other energy intensive industries such as manufacturing, pulp and paper, petrochemical, and iron and steel. Improvements in energy efficiency or an ongoing North American economic recession could reduce natural gas demand.

Power generation gas demand in Canada also increases by 0.16 Tcf, mainly due to the construction of new natural gas-fired power generation facilities in Ontario and Alberta.



Sources: Statistics Canada, various consultants

Ontario's policy to close coal-generating plants and replace them with natural gas plants would create a heavier dependence on new natural gas-fired capacity to meet peak Ontario electric demand.

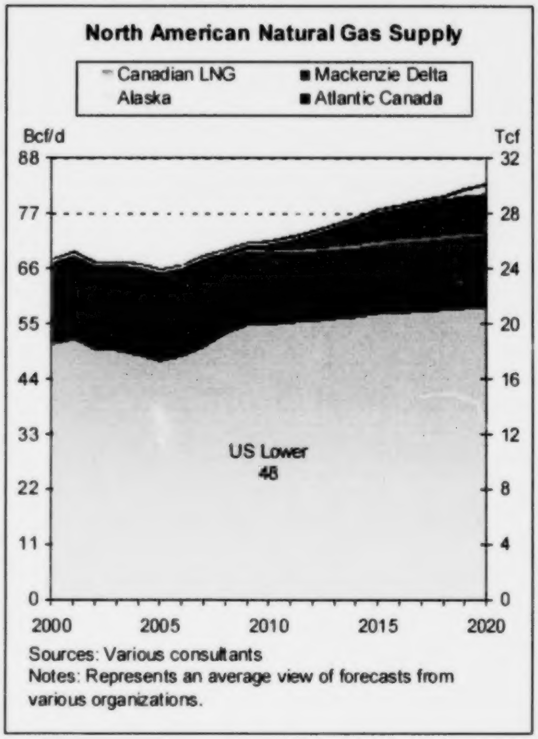
Industrial and power generation demand accounts for 68% and 17% of the growth in Canadian demand over the forecast period respectively, while residential and commercial demand is expected to grow at a modest rate of approximately 1.3% per year.

■ North American Natural Gas Supply

According to the averages of the forecasts used in the figure at top left on the following page, North America will experience slightly higher production in many of its supply basins. This contrasts with the previous consensus forecast that indicated declining Lower-48, and Western Canada Sedimentary Basin (WCSB) production between 2008 and 2020. While drilling costs have increased, conventional basins have matured, natural gas prices have weakened, and production from unconventional resources has increased, particularly in the United States.

Though Canada has yet to produce significant volumes from shale or tight gas, these resources, located particularly in northeast BC, are expected to greatly contribute to WCSB production in the future.

The big natural gas supply story last year was regarding higher levels of LNG imports to North America. However, the outlook for LNG is now considerably more pessimistic. LNG imports to the United States in 2020 are now forecast at 6.2 Bcf/d—down 55% from last year's forecast



of 13.9 Bcf/d. Forecasted Canadian LNG imports, despite being considerably less than US imports, have fallen just as drastically—56%, to only 0.8 Bcf/d from 1.8 Bcf/d. Still, given the consensus forecast, LNG is expected to supply 8% of North America's energy needs in 2020, up from the 2-3% LNG currently supplies.

The average forecast start dates for the Mackenzie Gas Project and the Alaska natural gas pipeline are 2017 and 2020 respectively. The start dates announced by proponents are 2014 and 2018 respectively.

Overall, North American natural gas supply will increase from 25.6 Tcf in 2008 to 30.4 Tcf in 2020, with 27.8 Tcf being supplied by domestic sources.

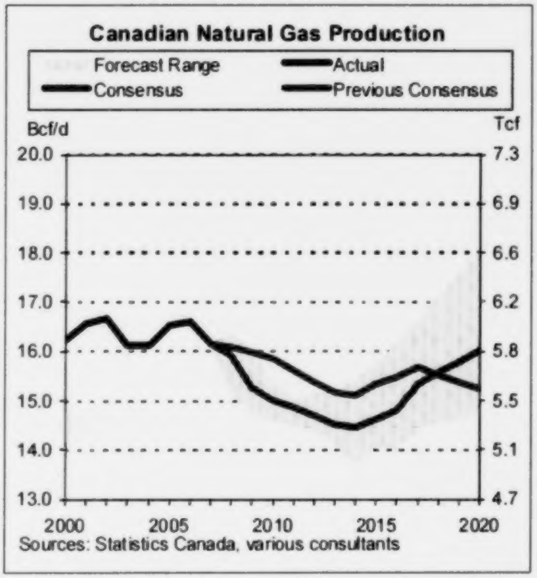
Note: While every effort is made to ensure accuracy in this report, due to the exclusion of balancing items and annual storage changes calculated by each organization, the consensus forecast for the North American natural gas supply may not equal the consensus forecast for demand in each year.

■ Focus on Canadian Production

The consensus forecast for Canadian natural gas production compared with the consensus forecast from last year's report is slightly more pessimistic in the short-term. Higher drilling costs and lower natural gas prices have reduced WCSB conventional production. By 2013, new production from BC shale will begin to reverse the declining WCSB trend, and by 2018, the Mackenzie Gas Project will add an additional 0.7 Bcf/d to Canadian production.

Economics have improved considerably for shale projects—new technologies have lowered the cost of drilling and "fracing" shale rock. High initial volumes improve the financial return from each well. Unlike several shale gas basins located in the United States, northeast BC currently lacks suitable infrastructure to transport shale gas or tight gas to market. Individual forecasts for BC production in 2020 vary between 2.7 Bcf/d and 5.1 Bcf/d.

Still, there is a divergence of views regarding Canadian production—with views differing primarily on the start date of the Mackenzie Gas



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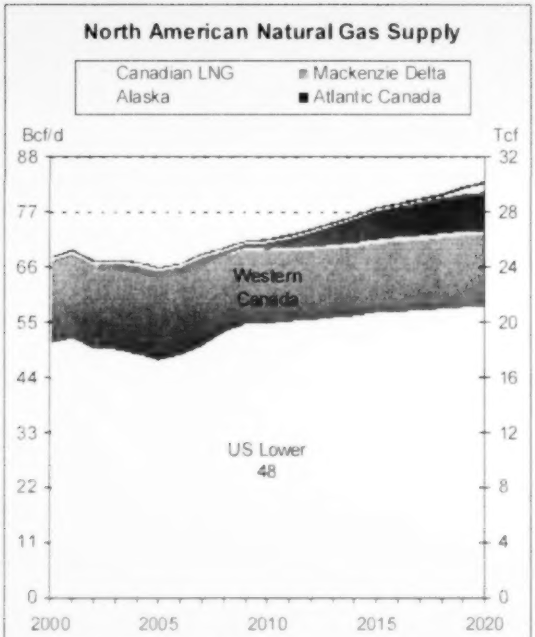

Sources: Various consultants
Notes: Represents an average view of forecasts from various organizations.

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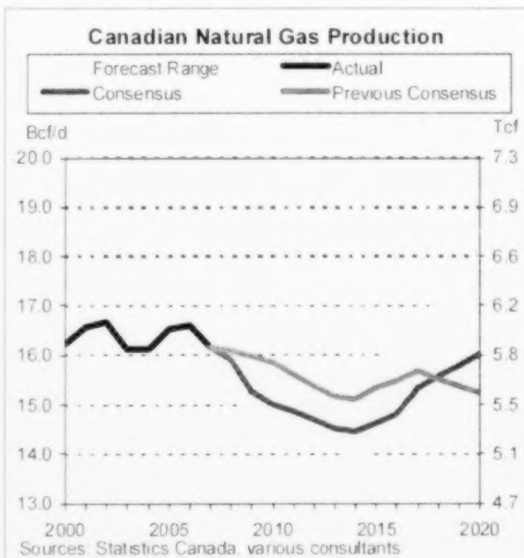


Project and the extent of the decline in conventional gas production in the WCSB.

The average expectation is that Canadian natural gas production will remain stable at 5.9 Tcf in 2020, which is roughly the same volume produced in 2007. However, production will bottom out at 5.3 Tcf in 2014 before reversing its downward trend.

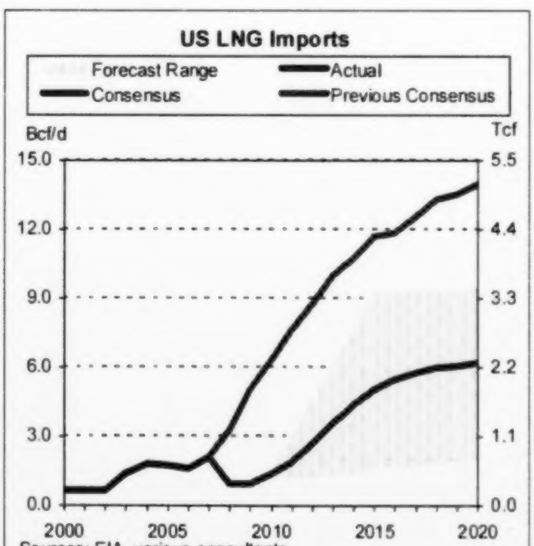
■ LNG Imports

Over the past year, many forecasts have changed dramatically regarding LNG imports into North America and are showing increased pessimism for the extent of LNG's role in the North American natural gas market.

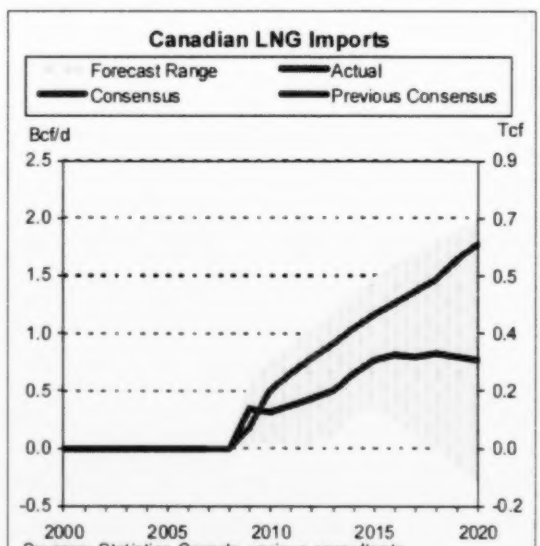
Last year, forecasts for LNG imports into the United States ranged between 10 and 16 Bcf/d by 2020, with an average forecast of 13.9 Bcf/d. Now, forecasts for LNG imports range between two (2) and 9.4 Bcf/d, with the consensus forecast of 6.2 Bcf/d in 2020. The short-term view amongst all consultants and the EIA has also changed considerably with declining and low LNG imports to the US between 2008 and 2010. Import growth picks up after 2010, but at a much slower pace than the consensus forecast from last year's report.

LNG imports to Canada are smaller in magnitude relative to imports of LNG into the US. While Canada, at the time of publishing, does not import LNG, LNG imports are expected to rise to 0.8 Bcf/d by 2020. Canada's first LNG terminal, Canaport, is expected to begin receiving LNG supplies in 2009.

LNG will likely continue to play a large role in meeting North America's future natural gas demand. However, there is considerable uncertainty about how much of this demand will be met by LNG, and how much by domestic sources, particularly shale gas and Arctic gas.



Sources: EIA, various consultants



Sources: Statistics Canada, various consultants

■ North American Natural Gas Prices

Natural gas prices are driven by many factors, and as a result can be very difficult to predict. Weather, one of the largest drivers of natural gas prices, is random. Crude oil prices, which

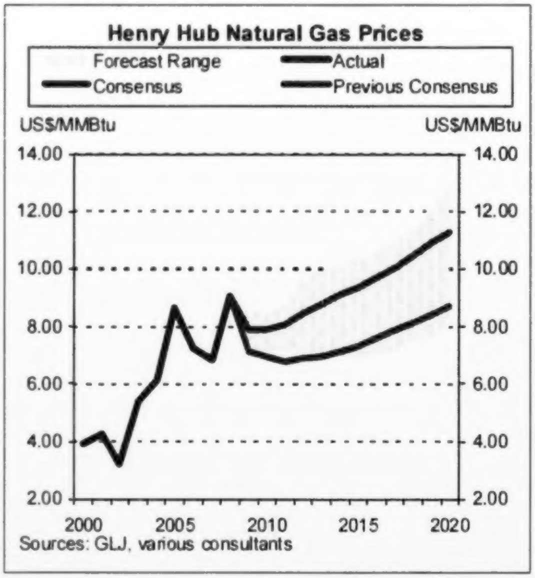
are difficult to predict, also have a large effect on natural gas prices.

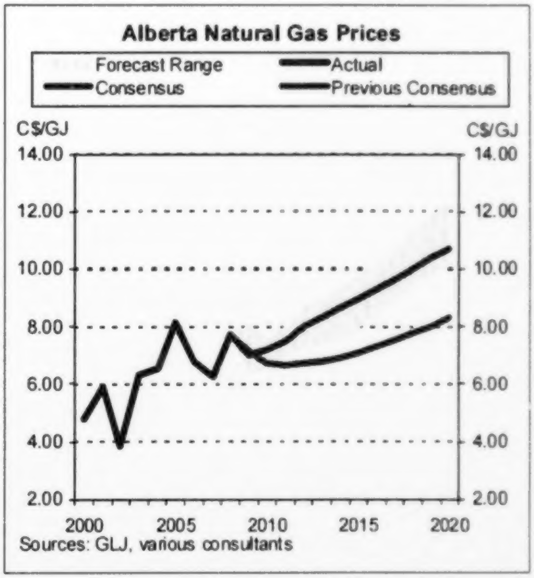
The following two figures illustrate the consensus forecast for two major natural gas markets—Henry Hub and the Intra-Alberta market.

The consensus forecast this year for Henry Hub prices is considerably more bullish than the consensus forecast reported by NRCan last year. The average forecast last year saw prices at US$8.71/MMBtu in 2020. The average forecast this year sees a price of US$11.30/MMBtu in 2020. The range of individual forecasts increases with the time horizon.

The consensus forecast for the Intra-Alberta market has prices rising considerably at 4.0% per annum, but within a tighter range than prices forecast for Henry Hub. In 2020, Intra-Alberta prices are forecast at $10.73/GJ, up from last year's forecast of $8.28/GJ.

While both consensus forecasts have prices rising in the long-term, this is a time of considerable uncertainty for natural gas prices and price expectations.





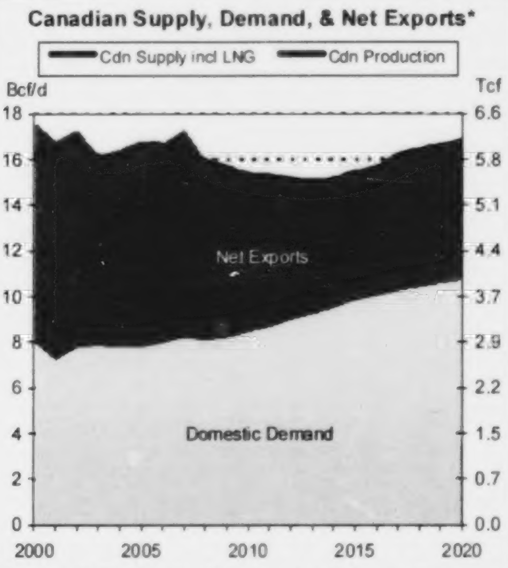
■ Natural Gas Exports, Imports & Revenues

■ Exports

The figure at top left on the following page shows the averaged views for projected Canadian natural gas supply (including LNG imports) and domestic demand. The difference between the two will be the amount of natural gas available to be exported to the US (e.g. net exports).

Using this approach, net exports to the US are projected to fall from 3.3 Tcf in 2007, to 2.2 Tcf in 2020. As Canadian natural gas demand is expected to grow faster than supply, net exports are pinched out to some degree.

Note: For the historical part of this graph, from 2000 to 2007, Canadian production is not



Sources: NEB, Statistics Canada and various consultants.
* Net exports vs. the US.

exactly equal to the sum of domestic demand and net exports. This is mainly because of storage changes.

It should be noted that net exports (gross exports minus gross imports) shown here refer to trade with the US only, and are the amounts of gas that physically flow from Canada to the US

LNG entering Canada is an import. However, after being imported, this gas becomes part of total Canadian natural gas supply.

■ Imports From The US

Imports by Ontario from the US have grown dramatically in recent years, and are likely to continue to grow, for several reasons. Firstly, natural gas demand in Alberta, for oil sands use in particular, continues to grow, while production is expected to decline. This leaves less gas physically available to leave western Canada, and serve eastern Canadian markets.

Secondly, natural gas production in the US from basins such as the Rockies and Barnett shale continues to grow. Pipelines, such as the Rockies Express, are being built to allow this gas to find markets. As this gas feeds into the US Midwest, there will be more gas available to be exported from the US Midwest to Ontario and Quebec.

Thirdly, most of the LNG imported by North America will land in the US. Once gasified, this could allow larger amounts of US gas to flow to Canada.

■ Producer Revenues

Given the price and volume outlooks contained in this section, it is a relatively simple matter to calculate the outlook for Canadian producer revenues.

Relatively stable production between now and 2020 combined with rising prices imply rising revenues for natural gas producers in Canada. A simple calculation using the consensus forecast prices and volumes (forecast production times forecast Alberta prices) yields total producer revenue of $62.2 billion in 2020 (in nominal dollars). Producer revenues in 2007 were $38.4 billion.

■ Ending Note

In the Executive Summary, Canadian dollars are noted as C$ and US dollars are noted as US$. For the remainder of the report, all prices are reported in Canadian dollars, except where noted as US$.

Perceptive readers may notice that an increase in Canadian demand plus net exports to the US should correspond with an increase in Canadian domestic production, minus the net annual change in storage. However, the data for 2007 illustrates that while production declined, domestic demand plus net exports rose, and this cannot be accounted for by a net draw from storage. This suggests a data problem which we cannot yet reconcile.

Though every effort is made to make this report as accurate as possible, it is nevertheless, a snapshot in time.

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Major Data Sources

1. Natural Gas Monthly, Energy Information Administration (EIA).
2. Annual Energy Outlook 2008, EIA, June 2008.
3. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2006 Annual Report, EIA, December 2007.
4. Marketable natural gas remaining established reserves in Canada 2006, Canadian Association of Petroleum Producers (CAPP).
5. Energy Statistics Handbook, Statistics Canada.
6. Weekly Storage Reports, Gas Daily, quoting surveys of US and Canadian storage volumes by EIA and Canadian Enerdata, respectively.
7. Canadian Natural Gas Focus, GLJ Energy Publications Inc.
8. Baker Hughes Rig Counts, Baker Hughes Web Site: http://www.bakerhughes.com/
9. Export statistics provided to Natural Resources Canada by the National Energy Board (NEB).
10. Canadian Energy Overview 2007, National Energy Board (NEB), May 2008.
11. Alberta's Energy Reserves and Supply/Demand Outlook 2008-2017 (ST98-2008), Energy Resources Conservation Board (ERCB), June 2008.
12. Various consultants on retainer to Natural Resources Canada.